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Preventative Maintenance and Reliability Study for the Central Heating and Power Plant at Fort Wainwright, Alaska

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Final Report

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Abstract: The Technology Requirements Study for a new Central Heating and Power Plant (CHPP) at Fort Wainwright, Alaska (FWA) (Vavrin et al. 2006) recommended that if the option for a new CHPP were to be pursued, among the tasks suggested for further analysis was to determine predictive maintenance requirements and new technologies for the existing plant. This study was undertaken to develop a Preventative Maintenance (PM) assessment that includes a maintenance program overview for the major systems in the existing CHPP. The assessment entailed: (1) an identification of shortcomings and deficiencies of existing procedures and processes, (2) recommendations to overcome shortcomings and deficiencies, (3) development of a maintenance schedule, (4) development of an estimate of staffing requirements, and (5) development of a budget estimate for execution of the recommended PM program with breakout for costs, detailed annually for a period of 25 years. This study also identified, prioritized, and separately broke out new technologies and associated costs that would significantly improve the reliability of the existing CHPP.

Executive Summary

The Fort Wainwright Central Heating and Power Plant (CHPP) is critical to maintaining the operation of the military base. It provides electricity and steam to the entire installation including family housing. The CHPP was commissioned in 1954 with eight coal-fired stoker boilers and five steam turbine generators. Two boilers and one steam turbine have since been retired in place, leaving in operation six boilers of 150 kpph each, and four steam turbine generators totaling 18 MW. The electrical power supply is supplemented by an interconnection to the local electric utility, the Golden Valley Electric Association (GVEA).

The Fort Wainwright CHPP is an aging facility that has successfully accomplished its mission of supplying steam and power primarily by sheer overcapacity. If one boiler is lost due to malfunction, another is available because of the plant's redundant capacity; six boilers were installed when normally only four to five boilers are needed during even the coldest part of winter. The ability of the electric plant to import power from the Golden Valley Electric Association (GVEA) has historically allowed the power plant to lose up to two turbines and still be able to supply the electrical needs of the community. Historically, the plant has never had a failure so catastrophic that all output from the plant stopped. If such an event occurred in the winter, installation missions and personnel would be put at risk. The plant was redundantly designed specifically to prevent such an occurrence and to provide for future growth.

However, as the installation has grown, demands on the aging CHPP have also increased. The CHPP is losing the safety reserve it has enjoyed over the past 50 years, specifically with regard to its ability to meet the installation's electric power needs. With forecasted load growth (as referenced in ERDC/CERL TR-07-36), the loss of a single steam turbine generator could create significant problems for the installation. Preventative maintenance practices should be implemented to avoid such an outage and to ensure continued plant reliability. A preventative maintenance assessment was commissioned to meet this need.

Issues

At the request of Headquarters, Installation Management Command (HQ IMCOM), an assessment team visited the CHPP the week of 27 March

2006. The team plant's evaluated the current maintenance program and the status of equipment, training, and plant operation. The team also developed recommendations (Chapter 5) to maintain reliable plant operation. Major issues discovered during the evaluation were:

1. *There is no preventative maintenance program*, which means maintenance is generally reactive. This is due in part to the lack of formal maintenance budget and funding.
2. *Maintenance logs have no formal tracking system*. Furthermore, there are no equipment maintenance records. Access to equipment original equipment manufacturer (OEM) manuals and drawings must be improved, and staff should be trained in their use.
3. *Maintenance staff should be provided with appropriate training*.

Recommendations

It is recommended that FWA implement a Reliability Centered Maintenance (RCM) system to overcome these issues. An RCM system combines preventive, predictive, and overhaul maintenance with data collected from different sources, to facilitate maximum operational time at a minimum cost. Due to the limited information received regarding CHPP past operating history, recommendations in this report are to a large degree based on judgment and experience, and on manufacturer's recommendations for similar equipment.

Chapter 6 described candidate preventative maintenance diagnostic tools and their associated costs. These tools, not currently in use at the plant, are valuable tools for RCM:

- thermal imaging
- vibration analysis
- oil analysis
- ultrasonics
- eddy current
- radiography
- environmental.

A proposed budget is included to estimate the cost of implementing an RCM system to provide the high reliability that is required of the CHPP. A budget estimate for the RCM program recommended herein will range in cost from $5-10 million per year between 2006 and 2030 (costs are in budget year dollars). Out of that estimate, $1.2 million per year will be budgeted for Computerized Maintenance Management System (CMMS) hardware and labor. Table ES1 lists the cost of implementing the RCM program in year 2006 dollars. Table ES2 lists the cost of implementing the RCM program in future dollars (i.e., budget year dollars) and were escalated from the year 2006 costs. Details for this budget are presented in Section 6.3 (p 69) and Appendix D.

A formalized RCM system built around a solid core of trained personnel can improve the reliability of the CHPP, if the money and resources are properly allocated. A decrease in the forced outage rate of 50 percent is a conservative estimate made from the implementation of RCM systems at other facilities (Smith and Hinchcliffe 2004). As the plant continues to age, the cost of overhauls will increase as will the periodicity of maintenance actions. This will result in the overall costs increasing from year to year. A maintenance plan is not a magical fix for capital funding needs. As a matter of fact, it will cost more in the near term to start a maintenance program. This is because the number of failures will not instantly stop just because a preventative maintenance program has been put into place. However, the use of the technologies described in Chapter 6 will provide the ability to determine problems before failures occur. This will result in the ability to control the downtime of the machine and have maintenance occur when determined by the plant staff and not the equipment.

Table ES1. Estimated maintenance program cost summary ($ 2006).

Maintenance Cost Category	Estimated Maintenance Program Cost, (2006 dollars)					
	2006-2010	2011-2015	2016-2020	2021-2025	2026-2030	Total
Boilers 1 through 6	7,500,000	6,980,000	8,010,000	8,690,000	10,070,000	41,250,000
Steam Turbines 1, 3, 4 and 5	5,750,000	2,900,000	3,360,000	3,900,000	4,520,000	20,430,000
Balance of Plant	5,330,000	3,260,000	3,750,000	3,290,000	4,180,000	19,810,000
New Technology	320,000	190,000	240,000	190,000	240,000	1,160,000
Owner's Costs (Engineering @ 5%)	940,000	670,000	770,000	800,000	950,000	4,130,000
Project Contingency	4,960,000	4,200,000	5,650,000	6,740,000	7,980,000	29,530,000
Total Plant Maintenance Cost (excluding Staffing)	24,800,000	18,200,000	21,780,000	23,600,000	27,940,000	116,320,000
Total Plant Labor Cost (Recommended Staffing)	5,490,000	5,490,000	5,490,000	5,490,000	5,490,000	27,470,000
Total Plant Cost	30,290,000	23,700,000	27,270,000	29,100,000	33,430,000	143,790,000
Average Cost per Year ($/year)	6,058,000	4,740,000	5,454,000	5,820,000	6,686,000	5,751,600

Table ES2. Estimated maintenance program cost summary (future costs).

Maintenance Cost Category	Estimated Maintenance Program Cost, (Future Cost)					
	2006-2010	2011-2015	2016-2020	2021-2025	2026-2030	Total
Boilers 1 through 6	7,840,000	8,100,000	10,330,000	12,430,000	16,010,000	54,720,000
Steam Turbines 1, 3, 4 and 5	6,050,000	3,370,000	4,350,000	5,620,000	7,250,000	26,650,000
Balance of Plant	5,570,000	3,810,000	4,890,000	4,780,000	6,780,000	25,830,000
New Technology	320,000	220,000	300,000	270,000	370,000	1,480,000
Owner's Costs (Engineering @ 5%)	990,000	780,000	990,000	1,160,000	1,520,000	5,430,000
Project Contingency	5,200,000	4,880,000	7,300,000	9,700,000	12,770,000	39,850,000
Total Plant Maintenance Cost (excluding Staffing)	25,980,000	21,170,000	28,160,000	33,960,000	44,700,000	153,960,000
Total Plant Labor Cost (Recommended Staffing)	5,770,000	6,500,000	7,330,000	8,270,000	9,320,000	37,200,000
Total Plant Cost	31,740,000	27,670,000	35,500,000	42,230,000	54,020,000	191,160,000
Average Cost per Year ($/year)	6,348,000	5,534,000	7,100,000	8,446,000	10,804,000	7,646,400

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Preface

This study was conducted for Headquarters, Installation Management Command (HQ IMCOM) under Military Interdepartmental Purchase Request (MIPR) 6CCERB1011R, “Annex 46 Holistic Assessment Toolkit on Energy Efficient Retrofit Measures for Government Buildings (EnERGo)”; Project Requisition No. 127396. The technical monitor was Paul Volkman, HQ-IMCOM.

The work was performed by the Energy Branch (CF-E) of the Facilities Division (CF), Construction Engineering Research Laboratory (CERL). The CERL Project Managers were John L. Vavrin and William T. Brown III, who led the U.S. Army Engineer Research and Development Center (ERDC) Project Delivery Team (PDT), assisted by Dr. Thomas J. Hartranft and Michael R. Kemme. The work was done by Science Applications International Corporation and Worley Parsons under Delivery Order No. 0002, Contract No. W9132T-04-D-0001. Special acknowledgement is given to the Fort Wainwright, Alaska Directorate of Public Works (FWA DPW), Headquarters, U.S. Army Corps of Engineers (HQUSACE), Corps of Engineers Pacific Ocean Division (CEPOD), Corps of Engineers Alaska District (CEPOA), Pacific Region Office, Installation Management Command (PARO-IMCOM), U.S. Army Alaska (USARAK), and the Directorate of Engineering, U.S. Army Engineering and Support Center, Huntsville (CEHNC) for providing assistance required to conduct this study. Dr. Thomas J. Hartranft is Chief, CEERD-CF-E, and Michael Golish is Chief, CEERD-CF. The associated Technical Director is Martin J. Savoie, CEERD-CV-T. The Director of CERL is Dr. Ilker R. Adiguzel.

CERL is an element of the U.S. Army Engineer Research and Development Center (ERDC), U.S. Army Corps of Engineers. The Commander and Executive Director of ERDC is COL Richard B. Jenkins, and the Director of ERDC is Dr. James R. Houston.

Unit Conversion Factors

Multiply	By	To Obtain
acres	4,046.873	square meters
British thermal units (International Table)	1,055.056	joules
cubic feet	0.02831685	cubic meters
cubic inches	1.6387064 E-05	cubic meters
cubic yards	0.7645549	cubic meters
degrees Fahrenheit	(F-32)/1.8	degrees Celsius
fathoms	1.8288	meters
feet	0.3048	meters
gallons (U.S. liquid)	3.785412 E-03	cubic meters
hectares	1.0 E+04	square meters
inches	0.0254	meters
miles (U.S. statute)	1,609.347	meters
pounds (mass)	0.45359237	kilograms
square feet	0.09290304	square meters
square inches	6.4516 E-04	square meters
square miles	2.589998 E+06	square meters
square yards	0.8361274	square meters
tons (2,000 pounds, mass)	907.1847	kilograms
yards	0.9144	meters

Terminology Used in this Report

A

ACC air cooled condenser

ASHRAE American Society of Heating Refrigeration and Air Conditioning Engineers.

B

B#3 Boiler no. 3, (for example)

Btu British thermal unit

C

cfm cubic feet per minute

CHPP Central Heating and Power Plant

CMMS Computerized Maintenance Management System

CM Condition based Maintenance

D

DA deaerator

DCS Distributed Control System

E

El electric

El&C Electrical, Instrumentation and Control

F

°F degrees Fahrenheit

FD forced draft fan

Ft feet

FW feedwater

G

gpm gallons per minute

GVEA Golden Valley Electric Association

H

h, hr hour

Hp horsepower

Hz Hertz, (frequency, cycles per sec.)

I

I&C instrumentation and controls

in Hg, a inches mercury, absolute

K

kV kilovolt

kVA kilovolt-amperes

kW kilowatt

M

Max. maximum

Min. minimum

MW megawatt

MWe megawatt electric

MWh megawatt-hour

MWt megawatt thermal

N

NA not applicable, not available

NDE non-destructive examination

O

O&M operation and maintenance

OEM original equipment manufacturer

P

P&ID Piping and Instrumentation Diagram

PM Preventative Maintenance

PPE Personal Protective Equipment

psi lb/square inch

PRV pressure reducing valve

R

RCM Reliability Centered Maintenance

RO Reverse Osmosis

S

ST steam turbine

STG steam turbine generator

T

TG turbo-generator, (turbine-generator)

U

UCC United Conveyor Company

USD United States Dollars

V

V volts

VF variable frequency

Y

y, yr year

1 Introduction

1.1 Background

The Fort Wainwright CHPP consists of six coal-fired boilers and four steam turbine generators that supply steam and electricity to the Post. The electrical power supply is supplemented by an interconnection to the Golden Valley Electric Association (GVEA), the local electric utility. The Fort Wainwright CHPP is an aging facility that has been successful in its mission of supplying steam and power primarily by its sheer overcapacity. If one boiler is lost due to malfunction or operator error, another boiler is available because of the redundancy of having six boilers installed when normally only four to five boilers are needed for the coldest part of winter. The ability of the electric plant to import power from the Golden Valley Electric Association (GVEA) has historically allowed the power plant to lose up to two turbines and still be able to supply the critical electrical needs of the community.

However, as the installation has grown, demands on the aging CHPP have also increased. The CHPP is losing the safety reserve it has enjoyed over the past 50 years, specifically in its ability to meet the installation's electric power needs. With forecasted load growth, the loss of a single steam turbine generator could create significant problems for the installation. Preventative maintenance practices should be implemented to avoid such an outage and to ensure continued plant reliability. A preventative maintenance assessment was commissioned to meet this need.

1.2 Objective

The objective of this work was to:

1. Assess the state of the maintenance management system at the CHPP
2. Identify areas in the current process requiring improvement
3. Recommend changes to implement these improvements
4. Produce proposed maintenance schedules for the major systems
5. Estimate staffing requirements, materials, and equipment required for the maintenance program
6. Estimate a budget required to execute the recommended program over a period of 25 years.

1.3 Approach

CERL led an assessment team with contracted assistance from Science Applications International Corp. (SAIC) and WorleyParsons, Inc, which visited the CHPP during the week of 27 March 2006. The current maintenance program was evaluated as was the status of equipment, training, and plant operation. The team developed recommendations (documented in this report) to ensure that reliable plant operation is maintained.

The remainder of this report is organized into the following Chapters:

- Chapter 2 Brief Plant Description
- Chapter 3. Overview of Existing Maintenance Management Program
- Chapter 4. New Technologies
- Chapter 5. Overview of PM Budget
- Chapter 6. Results and Discussion
- Chapter 7. Conclusions and Recommendations.

1.4 Mode of technology transfer

This report will be made accessible through the World Wide Web (WWW) at URL: http://www.cecer.army.mil

2 Brief Plant Description

This chapter briefly describes the major CHPP plant systems:

- Boilers
- Steam Turbine Generators
- Steam System
- Feedwater System
- Condensate System
- Coal Handling system
- Ash Handling System
- Cooling System
- Water Treatment System
- Electrical System
- Instrument and Controls System
- Environmental (Title V) Requirements.

A more detailed review of the plant design and operating characteristics can be found *Technology Requirements Study for a New Central Heating and Power Plant at Fort Wainwright, AK* (Vavrin, et al. September 2006), prepared by this team as part of a previous task.

2.1 Boilers

Figure 1 shows a simplified diagram of the boilers, steam, and steam turbine systems. The CHPP is equipped with eight boilers. Boilers 1 and 2 have been abandoned in place since a major plant reconstruction in 1954. Boilers 3 through 8 were commissioned in 1954 and are still in operation. The boilers are identical, manufactured by Wickes Boiler Co. and erected by Wyatt and Kipper Engineers. Boilers 3 through 8 are arranged in two rows, with odd numbered units on the east side and even numbered units on the west side of the building.

The boilers are R-model, two-drum, bottom supported, natural circulation, balanced draft technology, each equipped with six continuous discharge under-throw type spreader stokers and one forward traveling grate. The boiler furnace is a bent-tube type, refractory-lined and steel cased.

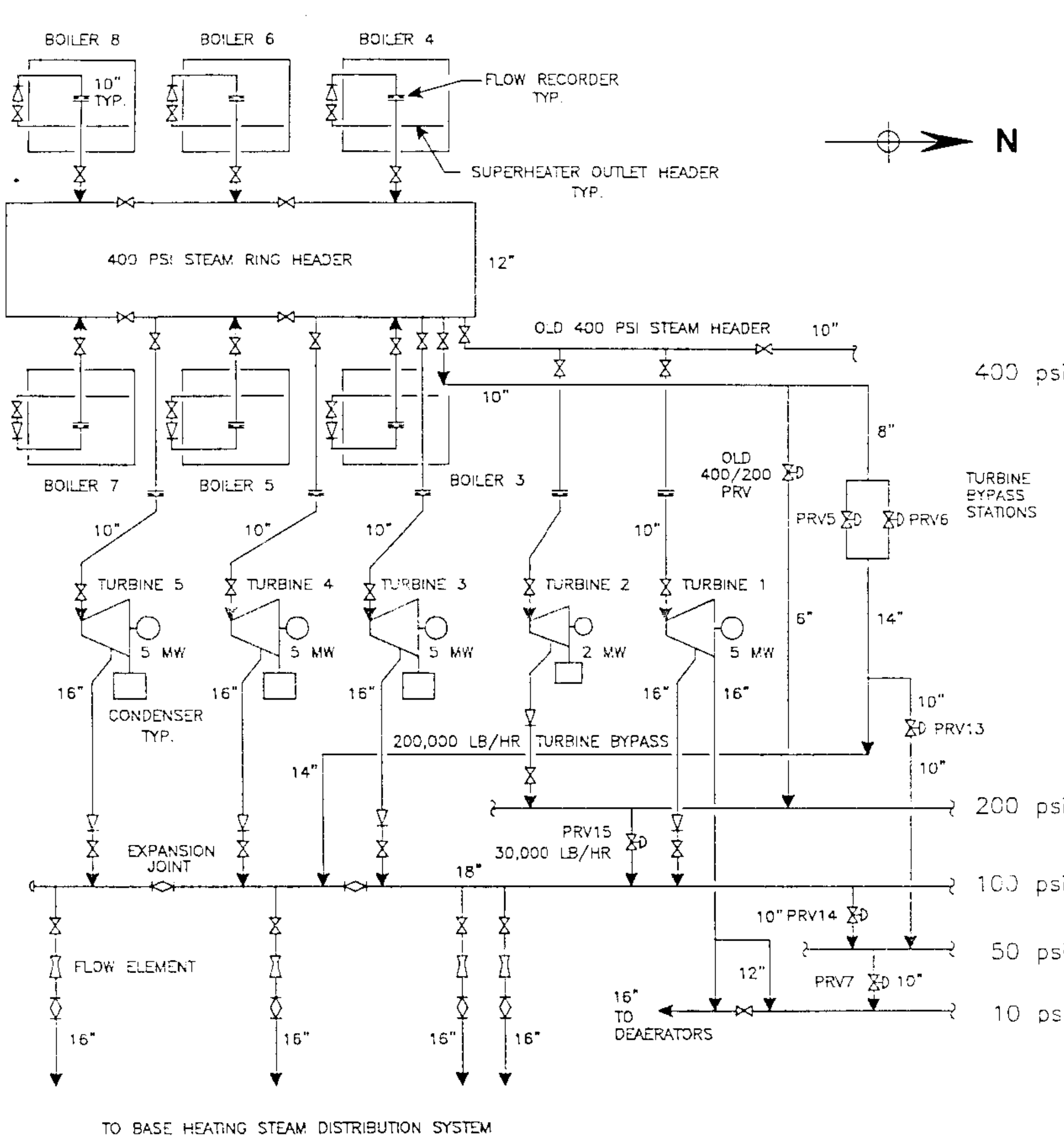

Figure 1. Simplified diagram of boilers, steam and steam turbine systems (Source: Raytheon Engineers and Constructors August 1996).

The boilers are equipped with pendant type convection superheaters and drainable bare-tube economizers. Overpressure protection for each boiler is accomplished by five safety relief valves (SRV), set in 5 psig increments from 455 psig to 475 psig. The boilers have a continuous rating of 150 kpph steam flow with a design pressure and temperature of 425 psig/ 670 °F (DEFC March 2005).

2.2 Steam turbines

The plant is equipped with five steam turbine-generators (STG), all manufactured by GE. Turbines 3 through 5 are single casing controlled extraction machines, each with a rated output of 5 MWe on 12.47 kV generator terminals, discharging to a water-cooled surface condenser with a design exhaust pressure of 1.5-in. Hg, The condenser OEM is Graham Manufacturing of New York. STG-1 is a 5 MW back-pressure machine, supplying 10 psig exhaust steam for plant needs. Due to the reduced plant demand for 10 psig steam, the STG-1 output is currently limited to a nominal 3 MWe during the summer and approximately 4 MWe during the winter. STG-2 is a 2 MWe condensing machine that has been abandoned in place. The 100 psig steam extracted from turbines 1 and 3 through 5 is sent to the Fort Wainwright heating system via four feed lines.

Cooling water for the condenser has been supplied from the cooling pond. A project currently under way will replace the water-cooled condensers with air-cooled condensers (ACC). This project is expected to be completed in September 2007 (personal communication with Darrell Jaeke). The ACC design is based on 5 in Hg, turbine exhaust pressure at dry bulb (DB) ambient temperature of 82 °F (1 percent ASHRAE design temperature) (U.S. Army Corps of Engineers, Alaska District 20 September 2004). It is assumed that the turbine operation with an ACC will not result in an increase of the turbine performance deterioration rate and will not require an increased maintenance frequency.

2.3 Steam

The six boilers are connected to a 12-in. steam loop header with sectionalizing valves. This steam header operates at 400 psig and 650 °F. From the 400 psig steam header, a 10-in. branch supplies STG-1 and the new boiler feed water pump's steam turbine drive. Three additional 10-in. branches from the steam header supply the other three steam turbines. A fifth 10-in. branch supplies the existing boiler feed water pump's steam turbine drive (to be abandoned), two 400/100 psig pressure reducing valve (PRV) stations (200,000 lb/h total capacity), and a 400/200 psig PRV station.

A 30,000 lb/hr 200/100 psig PRV station is supplied by the 200 psig line. All of the 100 psig lines from the turbine extraction and the PRV station are connected to an 18-in. steam header. The 100 psig header supplies four

16-in. lines connected to the FWA heat distribution system. There is one desuperheater station on each of the 16-in. lines to the FWA heating system. There are two 100/50 psig PRV stations from the 100 psig heater that can supply steam to the plant heating system that includes the combustion air heating system. The combustion air is heated with a glycol system when the outside air temperature is below 20 °F. There is a 50/10 psig PRV station in series with one of the 100/50 psig PRV stations that supplies 10 psig steam to the deaerators (DEFC March 2005).

Sections of 400 psig, 100 psig, and 10 psig piping have been repaired/ replaced in recent years (U.S. Army Corps of Engineers Alaska District 11 March 2005). Existing 400 psig system valves were replaced with new rotary metal seated valves (U.S. Army Corps of Engineers drawing, M6-1, sheet 87) , existing 18-in. 100 psig system bellow joints were replaced, and new trap stations and new sectionalizing valves were installed on the 100 psig steam header to allow for repairs on the section of the header (U.S. Army Corps of Engineers drawing M7-1, sheet 90).

2.4 Feedwater

Figure 2 shows a simplified diagram of the feedwater and condensate systems.

The feedwater system (FW) is equipped with two deaerators (DA) supplied with 10 psig steam. The older DA was installed in 1940s, and a new DA was added in 1953. Each DA is sized to satisfy the full plant capacity. However, both DAs are interconnected and always in operation. Vent condensers were replaced on both DAs several years ago.

The FW system is equipped with three FW pumps. Two FW pumps are electric motor driven. One FW pump is dual electric motor and steam turbine driven on a common pump shaft with clutch and couplings. The pumps are approximately 4 years old. The plant is experiencing problems with these new FW pumps (vibration, clutch/brake, and bearing-oil lubrication problems). Major repairs have been performed on the new FW pumps by the manufacturer due to problems in design and workmanship (Personal communciation with Vic Lemay). The FW pumps supply water to a 10-in. feed water header that serves all boilers.

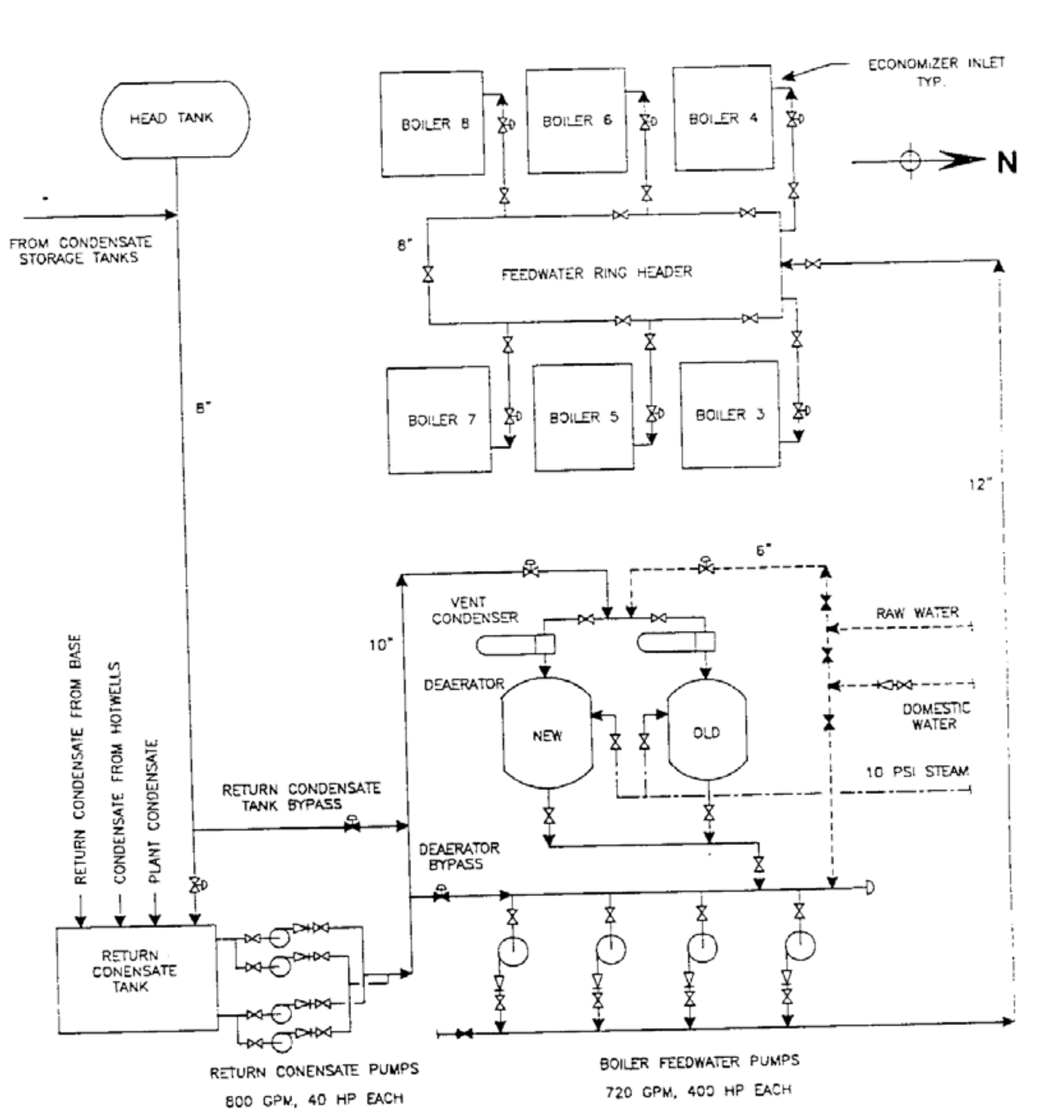

Figure 2. Feedwater and condensate simplified diagram (Source: Raytheon Engineers and Constructors August 1996).

The FW header was partially replaced in 2001. At that time, an oxygen scavenger was added to the new DA. A dispersant and neutralizing amine were added to the suction header of the FW pumps. The system's current peak duty is 460,000 lb/h (918 gpm) (Telephone conversation with Vic Lemay and Dave Brenner 12 April 2005). The system design peak duty is 778,000 lb/h (1,553 gpm) (H.W. Beecher Architects-Engineers 22 July 1952). The original pumps are in place and are being maintained as a backup (turned on for several minutes once a week).

2.5 Condensate

The CHPP condensate return rate is 75 percent of the district heating loop steam load. There are three condensate return mains from the installation system where the condensate flows into three sumps. Condensate from the sumps is transferred to a new 15,300-gal capacity condensate tank. Condensate from the tank is transferred by three condensate polisher booster pumps to a 925 gpm sodium cycle cation condensate polisher assembly. Each of the booster pumps has a capacity of 463 gpm at 100 ft of head with a 20 horsepower electric motor.

The polisher assembly has three polisher tanks, each with a 463 gpm treatment capacity. The polishers are regenerated with brine from a tank. The polished condensate flows to an 8,600-gal condensate receiver tank. Condensate from the receiver tank is pumped to the two deaerators by four condensate transfer pumps, each with an 800 gpm capacity at 150 ft head. Three of the pumps are electric driven, while the fourth is a steam turbine driven pump (DEFC March 2005).

All condensate tanks and pumps have been replaced and a condensate polisher has been added within the last couple of years. All condensate piping (up to the deaerator) including water treatment piping was replaced in 1997 (Raytheon Engineers and Constructors August 1996).

2.6 Coal handling

There are two coal handling systems at the CHPP, a south system and a north system. The north system has only a truck unloading system and is a backup system used only during a south system failure. The south coal handling system is the primary coal unloading facility. The CHPP receives its coal via rail from Usibelli Coal Mine, Inc., located in Healy, AK. Coal trains may consist of 80-ton and 100-ton cars. During the winter, the coal cars are directed to the thawing shed installed in 2002 and sized for nine cars. The south coal receiving system is equipped with two track grizzlies. Coal is dumped from the cars into either grizzly and proceeds into the track hopper that feeds apron feeders. Coal from the apron feeder is transferred to a belt conveyer, which feeds a coal crusher.

The belt conveyer is equipped with a magnetic head pulley to remove tramp ferrous material from coal. Coal size as received is 4-in. x 0-in. The coal crusher design rate is 175 tons/hr. It reduces coal to the size of 2-in. x 0-in. The coal crusher is equipped with a bypass system. The crushed coal is lifted by a bucket elevator approximately 120 ft, and feeds a two-way belt conveyer. The two-way conveyer can supply an over bunker flight conveyor network to feed the boiler bunkers, or can be reversed to discharge crushed coal to the coal yard. The over the bunker conveyer network is fully enclosed. Coal from the two-way conveyer is fed onto the west side feed conveyer that moves coal from south to north over the day bunkers of Boiler nos. 4, 6, and 8. The remaining coal is discharged to a cross conveyer that moves coal from west to east and feeds the east side conveyer. The east side feed conveyer moves coal from north to south over the day bunkers of Boiler nos. 3, 5, and 7. Any leftover coal after Boiler no. 7 on the east flight conveyer is discharged to another cross conveyer that moves coal to the west side completing the loop. Coal day bunkers are sized for 500 tons, for a total of 3,000 tons. Each day bunker is equipped with three gates. The coal feeding system is equipped with new 200 lb feed control scales.

The coal pile is located outdoors and typically contains a 90-day inventory. Coal can be reclaimed from the coal pile using a dedicated hopper, apron feeder and conveyer belt to the coal crusher.

The coal handling system operates one 10-hr shift per day with a typical system load of 14 cars/day. The peak load is 1100 tons/day. The design capacity is 150 tons/hr, and the actual average capacity is 110–120 tons/hr.

Most of the major coal handling system components were reported as being refurbished, replaced or modified between 2001 and 2005 (Alaska District August 1998). This includes track grizzlies, truck grizzlies, apron feeders, coal crusher, coal elevator, all lower-level conveyers, electric motors, over the bunker conveyer network, new coal bunker air cannons, chutes, grates, and non-segregating distributors. The north coal yard (backup) repair/upgrade was recently completed. The north coal system upgrade included the replacement of truck hopper, pan conveyor, belt conveyor, dust enclosures, magnetic separator, crusher and bypass, collection chutes, bucket elevator, and cross-over conveyor.

A new coal dust collection system consisting of two bag filtration systems, one with a 13,150 cfm fan and the second one with a 9,250 cfm fan, was placed into operation in 2004.

2.7 Ash handling

The CHPP ash collection system is a continuous vacuum type. The ash handling system includes heavier ash from the bottom ash hoppers, riddling ash hoppers and the multi-clone hoppers of the boilers, as well as fly ash. There is a reinforced concrete silo structure with an internal vertical steel wall that forms two separate silos, one for bottom ash and the other for fly ash, finer ash from the riddling hopper, and the existing multi-cone fly ash hopper from each boiler. The ash silos have funnel bottoms with pneumatic thumpers and steam heaters. The finer ash silo has a dry fly ash unloading mechanism; the other silo has a wet unloading system. The ash from the silos is unloaded to trucks that transport the ash to the landfill at the northern end of FWA.

Bottom ash disposal includes one clinker grinder in each of the four doghouses of the bottom ash hopper for each boiler. The bottom ash is conveyed by vacuum in an 8-in. pipe to primary/secondary centrifugal separators. The primary/secondary centrifugal separators are located at the top of the ash silo. At the separators, heavier ash is separated from the motive air and drops into the ash silo. The finer ash rides with the motive air and proceeds to a baghouse separator, the separated ash goes to the 168 ton ash silo, and the motive air is moved by a root blower and is exhausted though mufflers. The separators, baghouse, and root blower are all located on the top of the silo.

Ash from riddling hoppers from three boilers is conveyed by a 6-in. vacuum pipe. And there is another 6-in. vacuum main connecting the multi-cone fly ash hoppers of three boilers. There is another duplicate piping system for the other three boilers. All four 6-in. pipes from the boilers connect to an 8-in. main. The 8-in. main proceeds to the fly ash silo. The fly ash system at the silo is similar to the bottom ash system including the primary/secondary centrifugal separators, a baghouse and a root blower. All of the ash collection riser piping is made of UCC Durite metallic alloy. The horizontal branch piping is of UCC Nuvaloy lighter weight piping material.

A new baghouse was completed in 2004. This upgrade modified the pre-existing fly ash collection system at the CHPP. Flue gas from each boiler is ducted to the new baghouse that has separate streams for each boiler. Each stream has five modules that operate in parallel, and each include bags, cages, ash hopper, inlet duct and outlet duct. Clean gas out of the baghouse modules is exhausted by new ID fans at the new baghouse structure through a stack. The separated fly ash is pneumatically conveyed to the fly ash silo (DEFC March 2005)

The ash handling system has been completely rebuilt and modified. In this effort:

1. Ash collection piping was repaired/replaced and rearranged to separate fly ash and bottom ash collection.
2. The system was converted from intermittent type to continuous process and automated.
3. New 30 t/h clinker grinders were installed and bottom ash hoppers modified.
4. Ash silo bottoms were modified from flat to funnel type.
5. To reduce fugitive dust, the existing building was extended to provide a sheltered area for fly ash loading into vehicles. This area is equipped with a ventilation system connected to the baghouse.
6. Ash discharge was equipped with a dry unloading spout that bypasses the mixers.
7. A new pulse-jet cleaned bin vent filter was installed to vent conveying air, fluidizing air, and air displaced by ash.
8. Truck loading chutes were replaced with new ones lined with low friction coefficient abrasion-resistant liners.

Ash handling system design and most of the system components were supplied by the United Conveyer Company (UCC).

2.8 Cooling

At the present time, cooling water for the condenser is supplied from the cooling pond. A project currently underway will replace the water-cooled condensers with Air-Cooled Condensers (ACC). This project is expected to be completed in September 2007. The turbines will be connected to the ACC during successive outages. Table 1 lists the tentative schedule.

Table 1. ACC project schedule. (Source: Personal communication with Darrell Jaeke, ACC Project Manager).

Component	Completion Date
Air Cooled Condenser	September 30, 2006
Turbine #3 Connection	October 30, 2006
Turbine #4 Connection	March 17, 2007
Turbine #5 Connection	September 4, 2007

Each of the steam turbines: STG-3, STG-4 and STG-5 will be equipped with a three-cell, finned tube, A-frame configuration, single-pressure two-stage ACC with variable speed drives. The ACC units will be housed in the new building located east from the existing plant facility. Ancillary services would include tube bundle washing system, steam heat tracing, cold weather/freeze protection, electrical, and instrumentation and control (Alaska District 20 September 2004).

2.9 Water treatment

The make-up water system is a reverse osmosis (RO) system that was installed in 2003. The primary source of raw water is the domestic water connection. The backup raw water source is the onsite well. Raw water is filtered in a dual-media filtration assembly consisting of three tanks, each capable of filtering 125 gpm. The filtered water is heated in a plate-and-frame heat exchanger, using condensate as the heating media. The heated filtered water is de-chlorinated with sodium bisulfite, and proceeds to a single-stage, dual-train reverse osmosis unit. Each train can produce 100 gpm of treated water from a supply of 125 gpm raw water, rejecting 25 gpm. The RO treated water is disinfected in an ultraviolet disinfection unit and is stored in a new 120,000 gal treated water storage tank. The new tank is a bolted steel storage tank. The design capacity of the treatment system is 200 gpm (U.S. Army Corps of Engineers 26 June 2000).

2.10 Electrical

The Power Plant Electrical system includes 12.47 kV switchgear, 4160 V Bus 1 and Bus 2, 2.4 kV switchgear, 2.4 kV motor control centers, the 480 VAC system, 120 VAC system, 125 VDC system and a backup diesel generator for lighting. The power plant transformer yard connects the power plant's electrical system to Fort Wainwright's 12.47 kV Distribution System and GVEA's system.

Fort Wainwright's existing 12.47 kV distribution system consists primarily of overhead pole lines and is connected to the Power Plant's 12.47 kV switchgear. The overhead distribution system is not part of this report. The power plant is connected to the GVEA system through the power plant's switchyard. The GVEA system and any other connections to Fort Wainwright are not considered here.

The 12.47 kV and 2.4kV switchgear, collectively with the 4160 V medium voltage switchgear, was installed in the mid 1950s. The switchgear breakers were installed with the switchgear and not replaced unless they failed. There is no record of preventative maintenance activities for the medium voltage switchgear. There are three existing spare breakers.

There are no recorded maintenance records for the medium voltage breakers, although there are spare breakers available in case one of the in-service breakers fails. Medium voltage breakers are not designed to operate reliably for decades without maintenance. At some point the breakers will fail to operate. The failures will most likely occur when the breaker is under heavy load or when a fault occurs. Breaker failure poses a risk for plant operation, plant safety and personnel safety (Fonecon with Vic Lemay and Dave Brenner 12 April 2005).

The 480 V system consists of two station service transformers, two 480 V load centers, and ten 480 V motors control centers.

The 120 VAC Electrical System consists of numerous transformers and panels. The condition assessment documented in the 1996 Raytheon Study (Raytheon Engineers and Constructors August 1996) concluded that the 120 VAC system has many problems and will continue to deteriorate. The study further recommends a complete replacement of the 120 VAC system.

The 125 VDC system consists of two battery systems, 125 VDC Battery 1, and 125 VDC Battery 2. The 125 VDC system is approximately 9 years old and has not presented serious problems.

The backup lighting system consists of a diesel generator and an automatic transfer switch. When power is lost to the lighting system, the transfer switch automatically starts the diesel engine and transfers the lighting load to the generator when it is ready. The diesel generator and automatic transfer switch are relatively new and the plant has not experienced significant problems with their operation.

2.11 Instrumentation and control

The power plant instrumentation and control system mainly consists of the Westinghouse Distributed Processing Family installed around 1996. Westinghouse discontinued marketing this control system in 1997. This creates a problem for obtaining replacement parts, resulting in long lead times, high prices, and unavailability of key parts. The control system has 7000 to 8000 monitoring and control points, equally divided between the boiler and the turbine generator side. The control system is reported to have many limitations and needs to be upgraded to a current-generation control system (Alaska District 20 September 2004; Fonecon with Vic Lemay and Dave Brenner 12 April 2005; DEFC March 2005; Raytheon Engineers and Constructors. August 1996).

2.12 Title V requirements

Fort Wainwright's Title V operating permit contains all the conditions that the installation must comply with for its stationary air pollution sources (Environmental Conservation Air Quality Operating Permit, issue Date: 14 April 2003). The operating permit contains conditions for the CHPP that include preventive maintenance and quality assurance requirements. If the preventive maintenance requirements are not performed and documented properly and according to schedule, then Fort Wainwright would be in violation of the Title V permit. The CHPP equipment affected by these conditions include the baghouse, the continuous opacity monitoring system (COMS), the continuous emissions monitoring system (CEMS), the steam flow orifice plate, and the coal scales. The intent of this section is to show the specific portions of the operating permit that lead to required components of an overall preventive maintenance plan for Fort Wainwright.

The current operating permit expires in March 2008. Part of the application process for renewing the existing permit is the creation of a Compliance Assurance Monitoring (CAM) plan. Fort Wainwright is only required to develop a CAM plan for particulate matter less than 10 μm in diameter (PM_{10}). This is because CAM plans are only required for emissions that are reduced by an air pollution control device and the baghouse is the only air pollution control device used at the CHPP. The purpose of the CAM plan will be to determine and track measurements of baghouse performance that will show when the baghouse performance is beginning to slip and when it is likely that the CHPP is no longer meeting its PM_{10} concentration limit of 0.05 grains per dry standard cu ft. In the CHPP's current configuration, the plant will likely use measurements of pressure drop across the baghouse and opacity downstream of the baghouse as performance measurements. The CAM plan will formalize performance measurement data gathering, quality assurance, and set conditions under which Fort Wainwright needs to take action to improve baghouse performance. When instituted the CAM plan will potentially add components to the preventive maintenance plan.

2.12.1 Baghouse requirements

Condition 37 of the Title V operating permit states that "After installation of the baghouses the Permittee shall limit PM_{10} emissions to 0.05 grains per dry standard cub ft from Source IDs 1 through 6," where Source IDs 1 through 6 refer to the six individual boilers in the CHPP. Although the operating permit does not contain specific preventive maintenance requirements for the baghouse, the baghouse should be maintained according to the manufacturer's recommendations so that the 0.05 grains per dry standard cu ft concentration requirement can be sustained. The user manual includes daily, weekly, monthly, and 6-month checks of the sequence controller, filter bags, compressed air system, ash discharge system, ID fan, and dampers. Documentation of the preventive maintenance activities can help convince regulators that the baghouse system was properly maintained in the event that the baghouse has a problem meeting the particulate matter concentration requirements.

2.12.2 Continuous opacity monitoring system requirements

Condition 3 of the Title V operating permit covers visible emissions from the coal fired boilers. The condition limits exhaust effluent opacity to less than 20 percent for any 3-minute average in any 1-hr time period. This section of the permit contains the following specific requirements related to the preventive maintenance and quality assurance of the COMS:

> 3.2 Monitor, record, and report visible emissions by operating a COMS as follows:

c. Check the zero (or low level value between 0 and 20 percent of span value) and span (50 to 100 percent of span value) calibration drifts at least once daily in accordance with a written procedure meeting performance specification 1, 40 CFR 60, Appendix B

3.4 Conduct performance audits on the COMS as follows:

a. For a COMS that was new, relocated, replaced, or substantially refurbished on or after April 9, 2001, perform an audit that includes the following elements, as more completely described in Section 13, of the Department's Performance Audits for COMS, adopted by reference in 18 AAC 50.030, at least once in each 12 months:

(i) optical alignment;

(ii) zero and upscale response assessment;

(iii) zero compensation assessment;

(iv) calibration error check; and

(v) zero alignment assessment;

b. For a COMS that was new, relocated, replaced, or substantially refurbished before April 9, 2001, perform the same audits required under Condition 3.4a, except that Conditions 3.4a(i) through 3.4a(iv) must be performed at least quarterly;

Condition 94 of Section 13 provides much greater detail about specific requirements for each element of the COMS performance audit. Proper documentation of the daily zero and span checks and the annual performance audits are required to stay in compliance of these operating permit conditions. The Model OPM 2001 opacity monitor manual contains a section on preventative maintenance and suggested spare parts. A quality assurance plan is under development for the COMS to describe all activities required to maintain compliance with the operating permit. The operating permit also contains provisions for using EPA Method 9 for visually determining opacity when the COMS has been out of operation for more than 24 hrs or after a failed performance audit. Method 9 requires training renewal every 6 months to “recalibrate” their visual capability for determining opacity.

2.12.3 Continuous emissions monitoring system

Condition 29 of the Title V operating permit requires that Fort Wainwright:

> Calibrate, certify, operate, and maintain, in accordance with 40 CFR 60 Appendix B and Appendix F a continuous carbon monoxide (CO) and oxygen (O2) emission monitoring systems (CEMS) to measure CO and O2 emissions in the exhaust of Source IDs 1 through 6. The Permittee shall continuously monitor, compute, and record CO emissions based upon carbon monoxide and oxygen exhaust concentration measurements.

The CEMS information is used to calculate CO emissions on a daily and annual basis. Condition 29 also requires careful documentation of CEMS data and Condition 29.2 states that the documentation must include

> the date, time, and duration for which the continuous monitoring system required under Condition 29 is out-of-bounds, not recording data, or inoperable. Report each periodic Cylinder Gas Audit and Relative Accuracy Test Audit results conducted during the reporting period.

Fort Wainwright has carefully documented all maintenance and quality assurance requirements in a quality assurance plan (Fort Wainwright, AK March 2004). This plan includes a daily checklist based on the manufacturer's recommended preventative maintenance procedures. Continued adherence to this plan will allow Fort Wainwright to maintain compliance with Condition 29 of the operating permit.

2.12.4 Steam flow orifice plate requirements

Condition 35 of the Title V operating permit states that:

> The Permittee shall limit the monthly-average steam production to 150,000 pounds per hour for each of six (6) boilers, Source IDs 1 through 6 until a source test demonstrates compliance with emission standards at a higher load in accordance with Condition 5.2 and the department approves operation at the higher load.

This condition also contains the following specific requirements.

35.1 Calculate and record the average daily steam production rate (lb/hr) based on the hours of operation per day and steam production readings recorded at no less than 10-minute intervals.

35.2 Calculate and report in the Operating Report required by Condition 75, the monthly average steam production rate (lb/hr) for each of the past 6 months for each of Source IDs 1 through 6.

35.3 Report as excess emissions under Condition 73 for any period in which operations exceed the limits in Condition 35.

Condition 5.3 also covers the measurement and recording of steam production. This condition contains the following sections:

a. Operate and maintain a device to measure and record steam production in accordance with the manufacturer's written requirements and recommendations;

b. Except during breakdowns, repairs, calibration checks, and zero and span adjustments of the device, complete at least one cycle of sampling and analysis for each successive 15-minute period of boiler operation. From this data, calculate and record the average steam production rate for successive 1-hr periods. Maintain this data at the facility and make it available to the Department on request;

c. Within 1 year after the effective date of this permit and at such times as the Department may require, determine the relative accuracy of each monitoring device required by Condition 5.3a; and

d. Keep sufficient written records to show compliance with the requirements of Condition

5. In addition, keep records of the date and time identifying each period during which a device required by this permit is inoperative, except for zero and span checks, and records of the nature of device repairs and adjustments; on request of the Department, submit copies of the records.

Condition 5.4 states that *The Permittee shall*

a. Submit a report in accordance with Condition 73 whenever any of the following situations occur:

(i) when steam production exceeds a permit limit;

(ii) when the results of a source test exceed the particulate matter emission limit; and

(iii) if a steam production monitoring device malfunctions or becomes inoperable for four or more consecutive hours; in the report, identify the boiler, the cause of failure, and the anticipated time required to repair the device;

To maintain compliance with these conditions, the steam flow orifice plate must be maintained. These plates can be susceptible to erosion, which could change the measurement characteristics and pressure drop versus steam flow calibration. Therefore regularly scheduled inspections of the orifice plate should be added to a preventive maintenance plan for the CHPP.

2.12.5 Coal scale requirements

Condition 27 of the Title V operating permit requires that Fort Wainwright "Limit the annual coal consumption to a cumulative total of 336,000 tons per consecutive 12-month period for Source IDs 1 through 6." This condition also contains the following specific requirements.

27.1 Monitor and record the cumulative total monthly coal consumption for each of Source IDs 1 though 6, and calculate and record the cumulative 12 consecutive month total coal consumption.

27.2 Report in the Operating Report required by Condition 75, the cumulative monthly and 12 consecutive month total coal consumption for Source IDs 1 through 6.

27.3 Report in the Excess emission Report required by Condition 73, when the limits of Condition 27 are exceeded and identify the boiler.

To maintain compliance with Condition 27, the coal scales must be calibrated according to the manufacturer's recommendations. Fort Wainwright has been calibrating the scales on a regular basis. It is important however to document the calibration results in case there are ever questions about compliance with Condition 27.

3 Overview of Existing Maintenance Management Program

3.1 Current program procedure and issues

From 27 to 31 March 2006, a site visit was conducted to fully evaluate the current maintenance program in place at the Fort Wainwright CHPP. The site evaluation consisted of program review, records review, staff interviews, and equipment inspections. This chapter gives an overview of the plant maintenance program and identifies important issues.

3.1.1 Description of procedure

The plant maintenance program is an informal, mostly reactive system that addresses issues only when they impact operations. Since each power plant is unique, historical maintenance/repair records are the singlemost important input in establishing future maintenance and repair requirements. The lack of such records at the CHPP makes it very difficult to establish a baseline for future requirements.

Reactive maintenance actions are noted in two logs. One log is for mechanical items, and one is for Electrical, Instrumentation, and Controls (EI&C) items. Appendix A (p 78) gives examples of these two logs. The EI&C items are handled by the EI&C technicians on a self-prioritized basis. At the beginning of each shift, the Maintenance Lead reviews the mechanical log and issues work assignments to the mechanical maintenance technicians. The shift foreman for the operations shift working day shift will review the logs and provide input as to which issues are most pressing and check on the progress of previous issues. When an item has been corrected, the correction is sometimes entered in the appropriate log.

The system lacks a written procedure to document how maintenance actions are to be identified, assigned, tracked, and who is responsible for the items.

3.1.2 Description of issues

3.1.2.1 System is reactive

The maintenance system is almost completely reactive. No written procedures identify required actions and responsibilities. (A written procedure would also identify and include the records that needed to be kept.) Proper maintenance records are a very important part of any maintenance program. They allow the tracking of problems to identify patterns and provide data to analyze equipment maintenance costs versus repair or replacement costs to make intelligent decisions on the disposition of equipment.

The reactive maintenance logs were analyzed to show the systems and equipment that required the most attention between February 2005 and March 2006 (14 months). This time period was used strictly due to the availability of the logs from the plant personnel. Unfortunately, all reactive maintenance actions that are being performed are apparently *not* being recorded in the logs. Figure 3 shows the number of maintenance entries for each of the following major systems.

- boiler systems
- steam turbine generators and cooling system
- feedwater and condensate systems
- steam system
- coal handling system
- ash handling system
- water treatment system
- electrical and instrument and controls system
- miscellaneous systems and items.

Figures 4 to 11 show a breakdown of each system to show the equipment in each system that produces the most maintenance actions, and Table 2 lists a breakdown of maintenance entries by subsystem from February 2005 to March 2006).

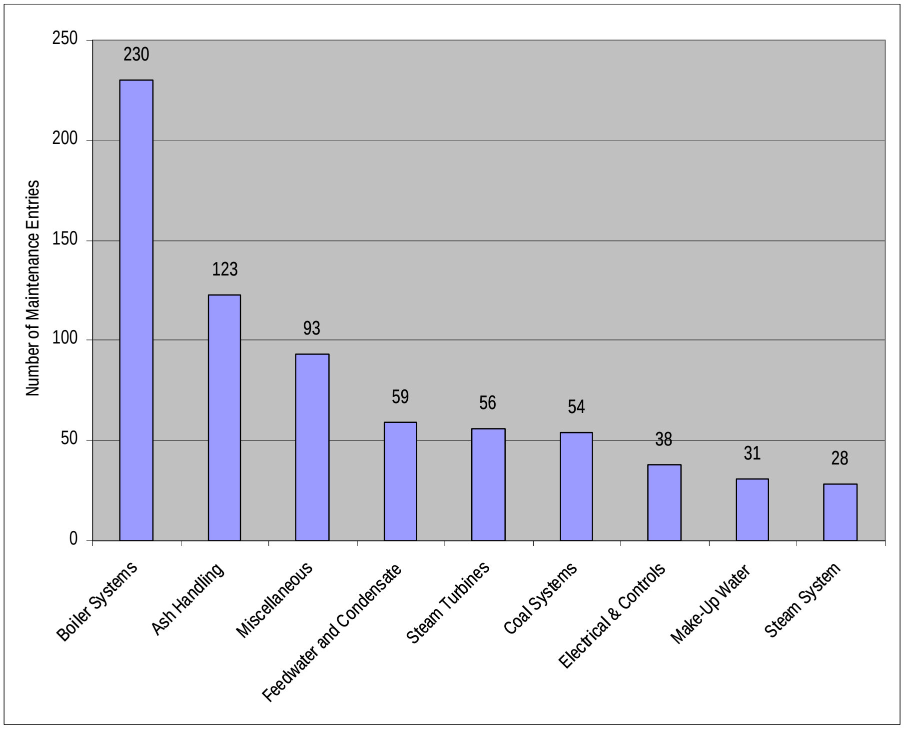

Figure 3. Maintenance entries by system (2/05 – 3/06).

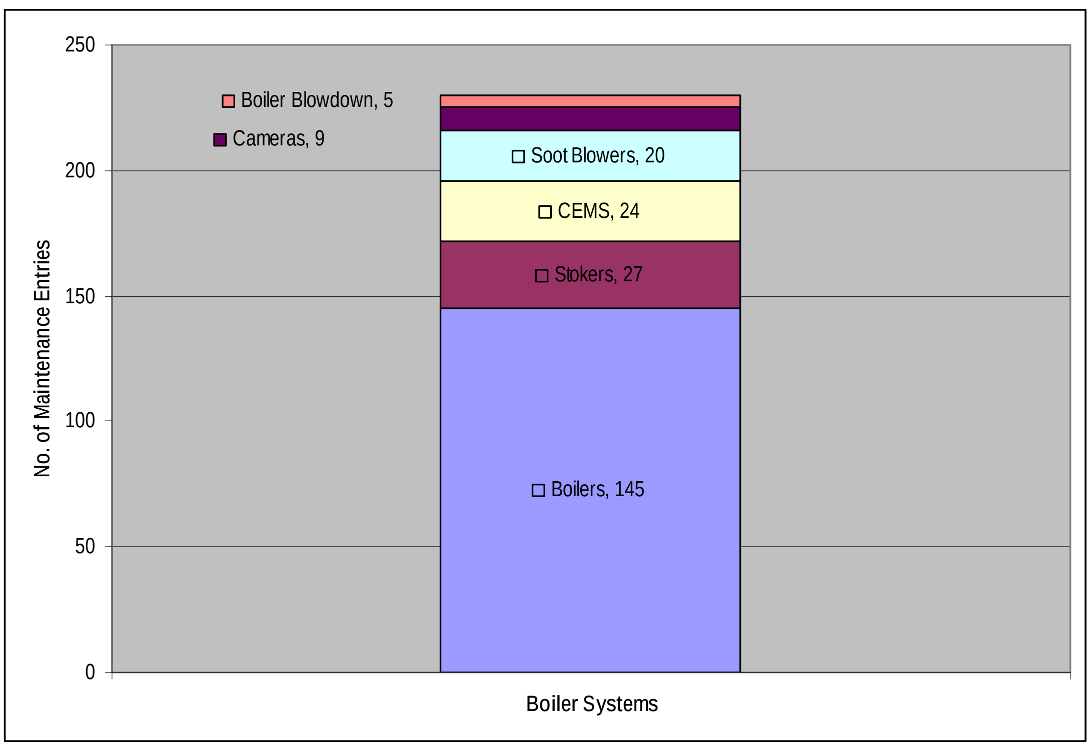

Figure 4. Boiler systems maintenance entries (2/05 – 3/06).

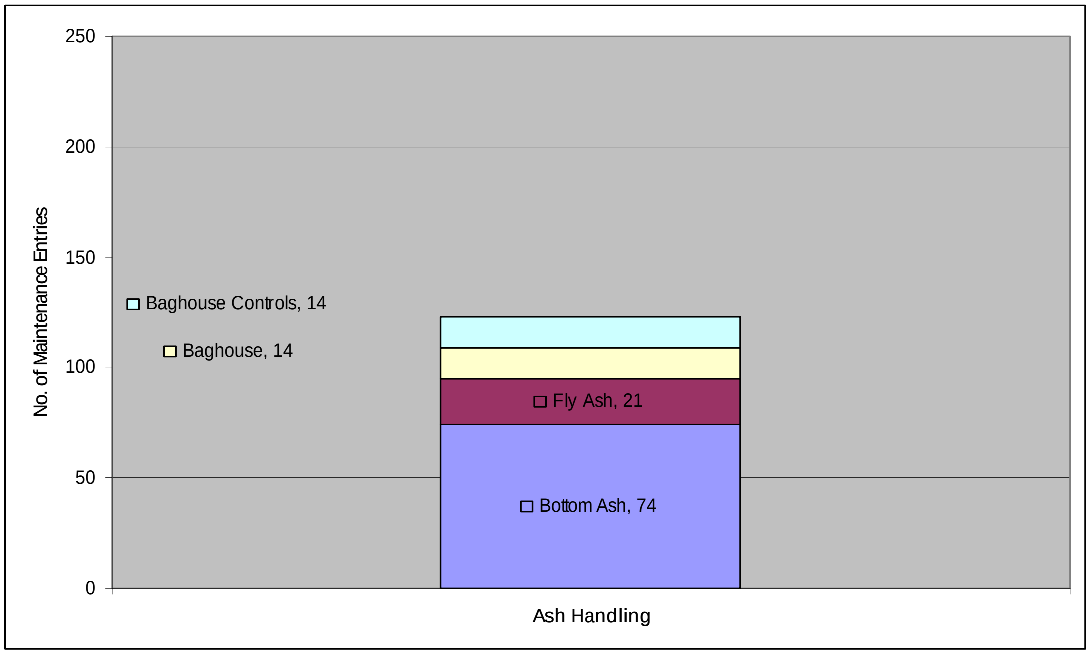

Figure 5. Ash handling maintenance entries (2/05 – 3/06).

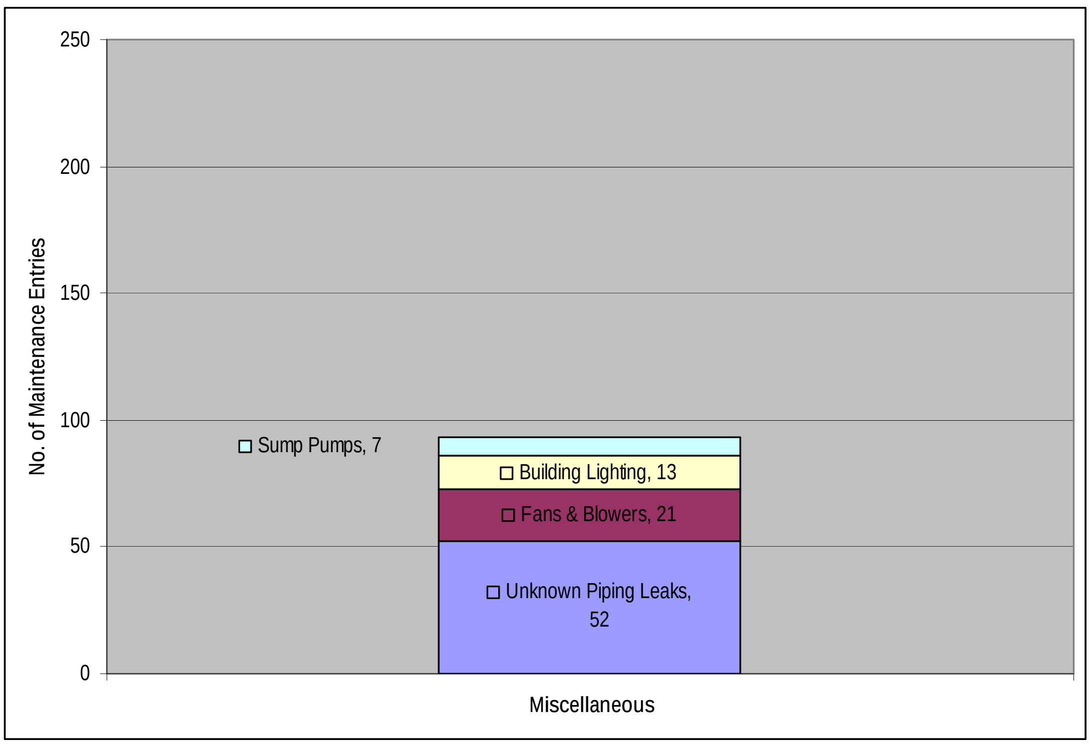

Figure 6. Miscellaneous maintenance entries (2/05 – 3/06).

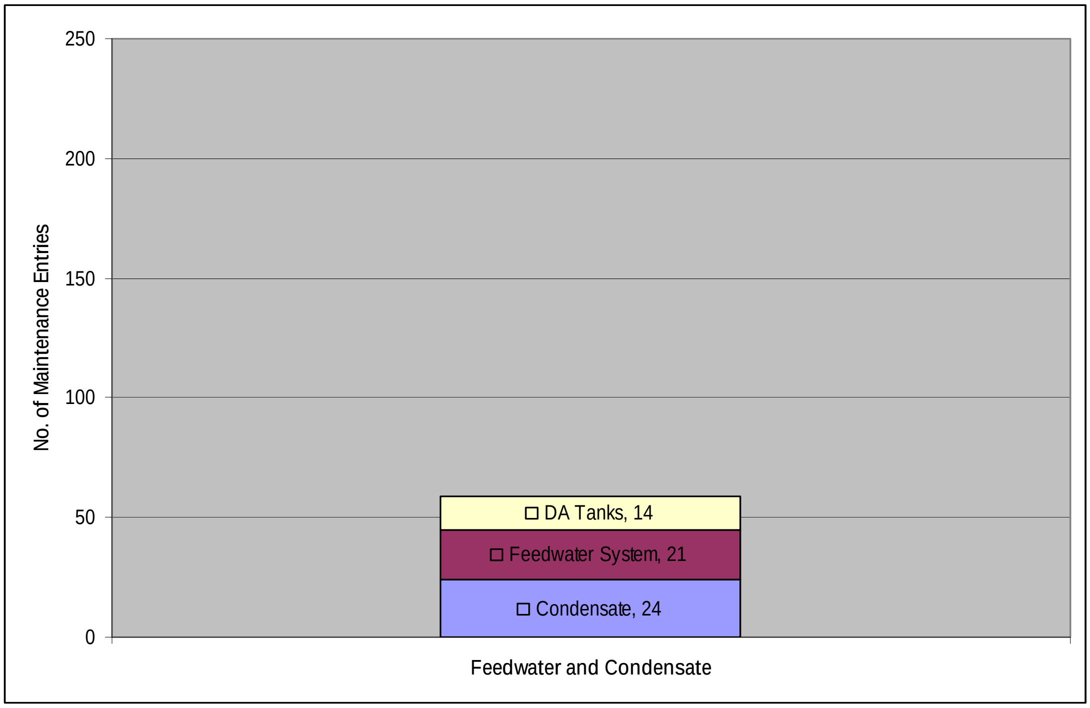

Figure 7. Feedwater and condensate maintenance entries (2/05 – 3/06).

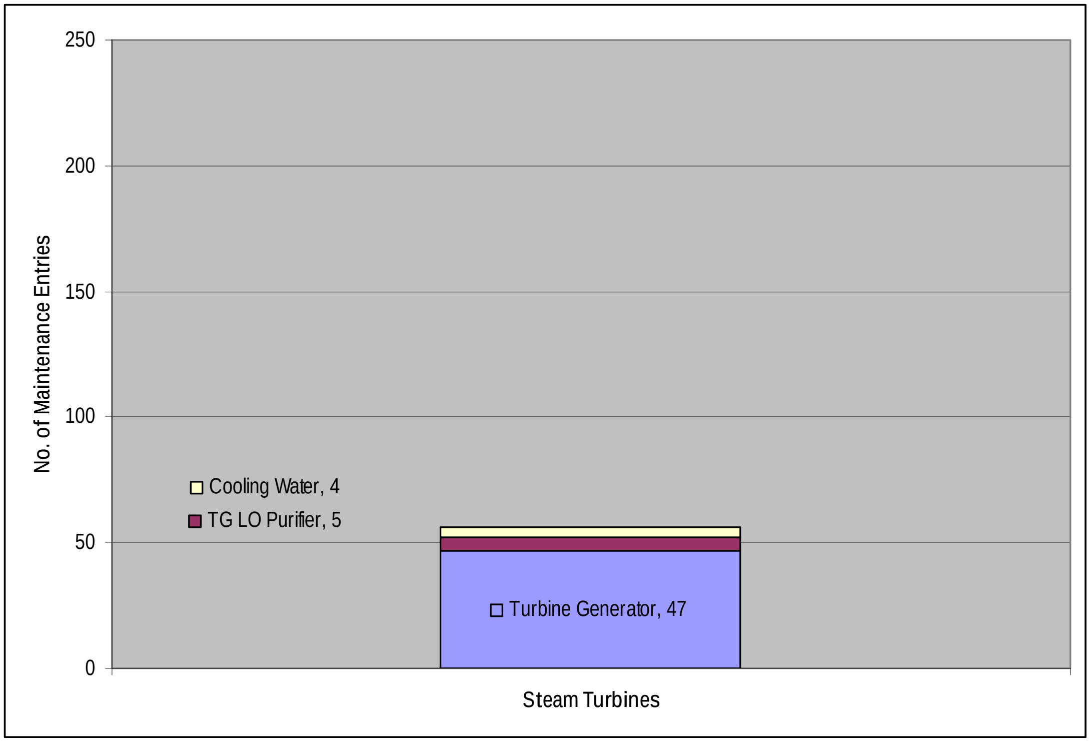

Figure 8. Steam turbines maintenance entries (2/05 – 3/06).

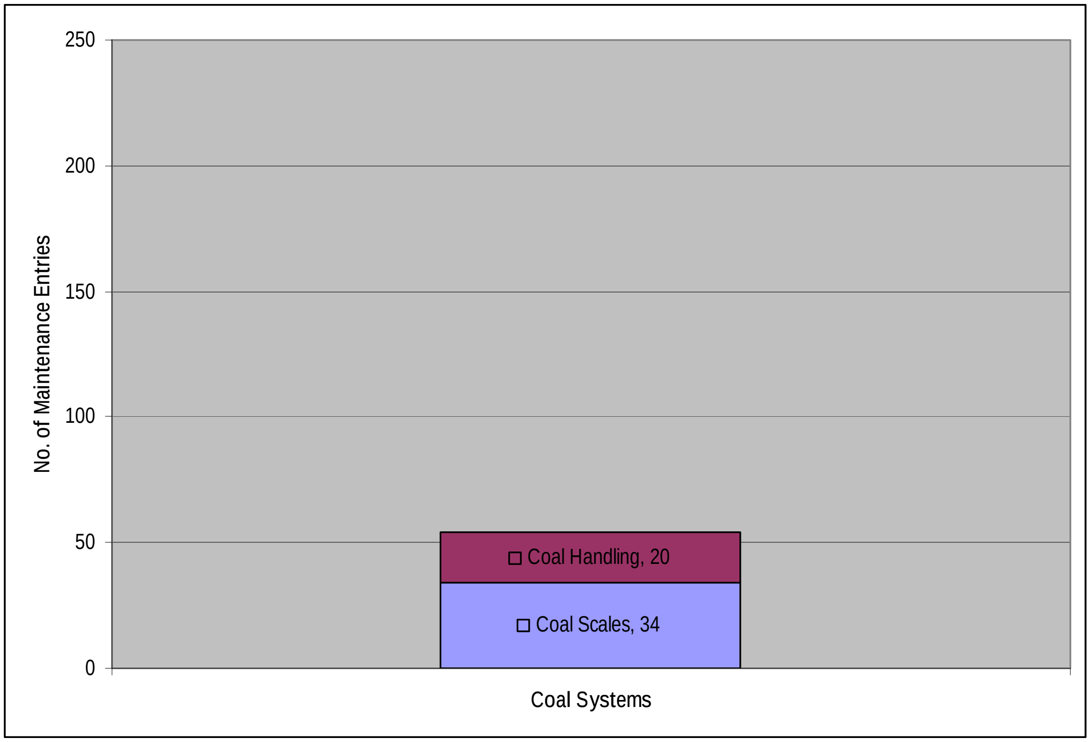

Figure 9. Coal handling maintenance entries (2/05 – 3/06).

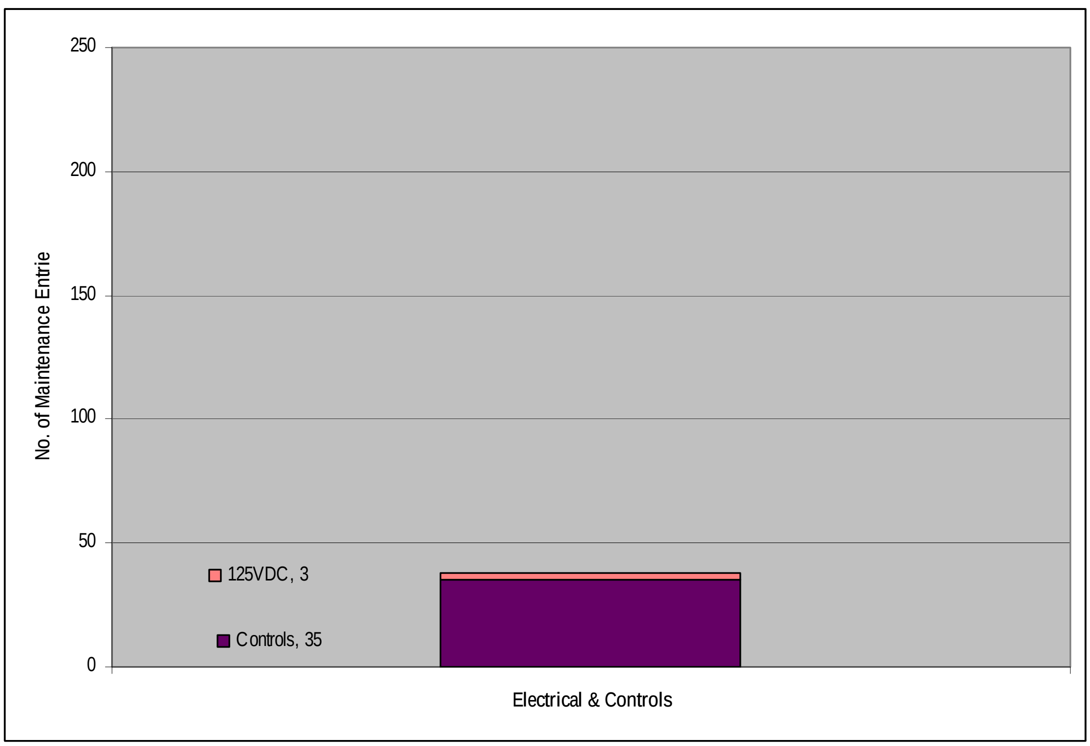

Figure 10. Electrical and controls maintenance entries (2/05 – 3/06).

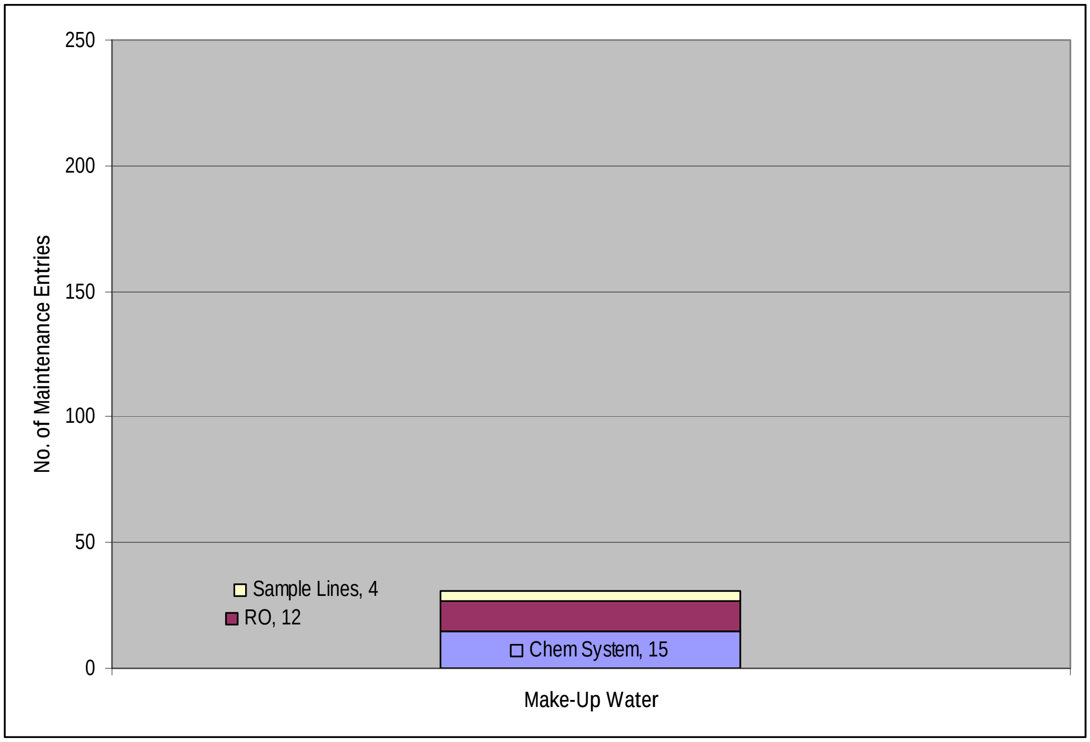

Figure 11. Make-up Water Maintenance Entries (2/05 – 3/06).

Table 2. Maintenance entries breakdown by subsystem (2/05 – 3/06).

System	Subsystem	Number of Entries	Percentage
Boiler		230	32%
	Boilers	145	20%
	Stokers	27	4%
	CEMS	24	3%
	Soot Blowers	20	3%
	Cameras	9	1%
	Boiler Blowdown	5	1%
Ash Handling		123	17%
	Bottom Ash	74	10%
	Fly Ash	21	3%
	Baghouse	14	2%
	Baghouse Controls	14	2%
Miscellaneous		93	13%
	Unknown Piping Leaks	52	7%
	Fans and Blowers	21	3%
	Lighting	13	2%
	Sump Pumps	7	1%
Feedwater and Condensate		59	8%
	Condensate	24	3%
	Feedwater	21	3%
	DA Tanks	14	2%
Steam Turbines		56	8%
	Turbine Generator	47	7%
	TG LO Purifier	5	1%

System	Subsystem	Number of Entries	Percentage
	Cooling Water	4	1%
Coal Systems		54	8%
	Coal Scales	34	5%
	Coal Handling	20	3%
Electrical and Controls		38	5%
	Controls	35	5%
	125 VDC	3	0%
Make-Up Water		31	4%
	Chem System	15	2%
	RO	12	2%
	Sample Lines	4	1%
Steam System	Steam System	28	4%
Total	*All Areas*	*712*	*100%*

The data listed in Table 2 show that the boilers are by far the highest maintenance action on the list, as evidenced by the greatest number of maintenance entries. Note that these counts represent the problems that were recorded in the maintenance log books, *not* all the maintenance actions that were performed during that time period. Plant personnel indicated that some items are passed to the maintenance department by word of mouth and are completed with no recordkeeping.

3.1.2.2 Training program is nonexistent

There is no continuing training of the maintenance department. In the modern world of continuously improving technology and techniques, continuous training of technicians is essential to ensure that high quality maintenance actions are being performed. OEM training is especially important to educate the maintenance staff on new equipment and refresher training for infrequent or large scale maintenance actions. A formal qualification and training program for the maintenance department would allow training to be tracked and would ensure that all technicians had a common base of knowledge. All technicians bring various specialized skills to the work environment. The CHPP should take advantage of those skills by assessing them and implementing a cross training program among the technicians. The maintenance department staff should also learn the various operations watch stations as part of the continuous training program. The knowledge of how the plant operates is invaluable in finding the root causes of equipment problems. Plant Management indicated a desire to begin training maintenance technicians in plant operations, but stated personnel shortages kept them from starting any kind of training program.

3.1.2.3 Plant documentation is not accessible

Currently, all plant manuals and drawings are kept locked on the ground floor in a room outside of the EI&C shop. Plant personnel do not have access to the documentation. Many of the interviewed personnel expressed surprised to find out that a room even existed that contained the plant manuals and drawings. Access to documentation is of the utmost importance to maintenance personnel to troubleshoot and repair equipment per manufacturer's instructions.

3.1.2.4 No formal maintenance planning or budget

The Maintenance Department currently has no formal budget that breaks down expenditures into a usable format. The proper allocation of resources requires preplanning and a solid budget. The listing of expenditures and planned expenditures allows the staff to track where money is going and if it is being used in the best possible manner. The Operations and Maintenance budget that was provided to the assessment team was the budget estimate for Fiscal Year 2005. The budget shows the labor costs for Fiscal Year 2005 and a few additional charges for tools, replacement materials, annual facility charge, and support utilities cost. The estimates are based on a percentage of the value of the facility. The line items are not broken down in any meaningful way relating to the maintenance of the plant. Table 3 lists these expenditures and the O&M labor costs.

3.1.3 Limited long range maintenance planning

The CHPP currently employs limited long range planning of maintenance and equipment resources. Some planning was done in conjunction with CERL (Brown 28 March 2006), but there is no evidence that this plan is being followed or is anything more than a wish list. The 1996 Raytheon study recommended the implementation of a comprehensive Non-Destructive Evaluation (NDE) program for critical CHPP equipment and systems. This program was never implemented (Raytheon Engineers and Constructors August 1996). Equipment overhauls and major maintenance actions are performed when equipment performance has degraded to a point where it is no longer useful or when a catastrophic failure has occurred. Long range planning has numerous advantages especially when coupled with a preventative maintenance plan. The long range plan can also be used to build a meaningful budget.

Table 3. CHPP O&M budget 2005.

Fort Wainwright, Alaska							
Central Heat and Power Plant							
(a)	(b) Wage Grades	(c) Personnel (FTE)	Percent	(d) Hourly Rate	(e) Overhead Rate	(f) Annual Salaries	(g) Total Labor Cost Plus O/H
Labor:							
General Foreman	WG-14 Step 3	1	85%	$ 32.42	32.85%	$ 57,511	$ 76,404
Shift Foreman	WG-12 Step 3	1	100%	$ 29.37	32.85%	$ 61,295	$ 81,431
Shift Foreman	WG-11 Step 3	3	100%	$ 27.84	32.85%	$ 174,306	$ 231,566
Operators	WG-10 Step 3	20	100%	$ 26.32	32.85%	$ 1,098,597	$ 1,459,486
Maintenance Crew	WG-10 Step 3	12	100%	$ 26.32	32.85%	$ 659,158	$ 875,692
Coal Unloading Crew	WG-7 Step 3	6	100%	$ 21.75	32.85%	$ 272,354	$ 361,822
Electrician	WG-10 Step 3	1	75%	$ 26.32	32.85%	$ 41,197	$ 54,731
Material Expeditor	WG-7 Step 3	1	80%	$ 21.75	32.85%	$ 36,314	$ 48,243
Sub-total		**45**					**$ 3,189,373**
Equipment:	Number of Units	Usage Percent	Depreciation Years	Total Cost New	Annual Cap. Cost	Operating Costs	Equipment Costs
Utility Truck (Pick up Tı	2	75%	8	$ 31,200	$ 4,386	$ 21,091	$ 25,477
Loader	1	100%	8	$ 84,500	$ 15,839	$ 14,061	$ 29,900
Backhoe	1	75%	8	$ 97,500	$ 13,707	$ 10,546	$ 24,252
Dump truck	2	95%	8	$ 110,500	$ 19,677	$ 26,716	$ 46,392
Safety Equipment	Lot	100%			$ 10,000	$ 10,000	$ 10,000
Sub-total							**$ 136,022**
Replacement Material (.25% Replacement Cost New of System)							**$ 375,000**
Hand Tool Expenses (.05% Replacement Cost New of System)							**$ 75,000**
Annual Facility Charge (0.1% of New Cost of System)							**$ 15,000**
Support Utilities Cost (Coal, Chemicals and others)							**$ 10,000,000**
Total O&M Expenses							**$ 13,790,395**
G & A Expenses (25% of O&M Labor)							**$ 797,343**
Total O&M and G&A Expenses							**$ 14,587,738**

Notes:
1.) Labor hour rates from Alaska area Wage Rate Schedule at ***www.cpms.osd.mil/wage/...***
2.) FTE = 2,087 hrs/year per OMB Circular A-76 guidance.
3.) Labor overheard rate per OMB A-76 guidance.
4.) Financed over depreciation life @ 10.0%
5.) Equipment operating cost $8.45/hr, five days a week and 80% availability

Note: The above labor includes all authorized positions including those positions not filled/

3.2 Issues not directly related to the study

Several important issues, not directly related to the scope of the commissioned study, were uncovered during the evaluation and are briefly recorded here. These issues include the safety program and plant operations.

4.2.1 Safety program

The safety program is not enforced. The study team witnessed numerous unsafe acts including moving hot coals from an operating boiler to start another boiler without gloves, face protection, or eye protection. The team also witnessed plant personnel using a portable drill without eye protection. The Personal Protective Equipment (PPE) available is not always in serviceable condition. It is recommended that an in-depth safety audit be conducted to determine shortcomings in the written safety program and in the training of plant personnel in all aspects of safety.

4.2.2 Plant operations- training and procedures

The plant operators are a dynamic group of individuals that all bring their own unique set of experiences and training to the operation of the CHPP. However, there is no set training and qualification program that forms a baseline of knowledge for all plant operators. During staff interviews, it was noted that operators had differing levels of knowledge about plant operations. Several maintenance technicians noted that the operators do not understand the function of some of the plant equipment and will erroneously note items as malfunctioning when they are performing infrequent functions. A formalized training and qualification program is recommended for the operators to ensure that all operators have a baseline of knowledge on plant systems and operations. Army Regulation 420-49 requires:

> a. *Operator training and certification*. Utility operators will be trained and certified in accordance with applicable existing Federal, State, local, or host nation standards. In the absence of Federal, State, local, or host nation certification requirements for boiler plant operators, the Fourth Class Power Engineer Certification Program of the National Institute for the Uniform Licensing of Power Engineers, Inc., will be the governing requirement. (*Utility Services* 19 September 2005)

This requirement explicitly states that all operators will be trained and certified to the state requirements. Alaska does not require that boiler operators be licensed therefore the operators must meet the certification requirements for a Fourth Class Power Engineer by the National Institute for the Uniform Licensing of Power Engineers, Inc.

Another issue related to plant operations is the lack of formalized normal operating and emergency operating procedures. For example, it was noted that one of the operators had stored a set of operating procedures in the water treatment laboratory, ostensibly so they would not become lost or damaged. Interviews revealed that most operators were unaware that operating procedures even existed. Operations knowledge is handed down from senior operators to junior operators by word of mouth. What the senior operator teaches is strictly at the discretion of the senior operator. While all the senior operators are extremely knowledgeable on the plant, not all are equally effective at communicating that knowledge. The lack of emergency operating procedures at the plant results in an environment where a small problem can cascade into a large problem due to operator inaction or incorrect action. It is recommended that both Normal Operating and Emergency Operating procedures be developed and incorporated into the Training and Qualification program (recommended above).

3.3 Current scheduling methodology

Plant maintenance staff are currently attempting to create a time-based preventative maintenance system. The program is very small and is not formalized with a procedure or record keeping requirements. The scheduling of these items is on a routine basis without planning around future outages or other events. The schedule of items is noted in Section 3.6 (p 31).

3.4 Major maintenance and overhaul assessment

There is currently no overhaul or outage schedule. While it is understood that the plant cannot ever completely shutdown, maintenance outages can be performed on a rolling basis along with the boilers and turbines. Work is not currently tracked by management. There is no master list of repair items for equipment that needs to be completed during the next equipment shutdown or overhaul.

3.5 Current maintenance tools and equipment assessment

Interviews with the maintenance staff indicate that there are enough hand tools, and they are in serviceable condition. Interviewed EI&C technicians stated a desire for updated test equipment. Specific equipment was not requested by the technicians and they did not elaborate about what they would like or what was deficient with the current equipment.

3.6 Preventative maintenance schedule review

The mechanical maintenance department has created a lubrication schedule to ensure all plant equipment is lubricated monthly. The lubrication schedule covers some of the recommended maintenance actions for pumps and motors throughout the plant. Appendix B (p 80) includes the schedule. The Maintenance Lead stated that the list is constantly being revised and expanded. The list does not cover all equipment at the plant or all maintenance actions that need to be performed.

The EI&C maintenance department performs weekly battery water level checks for the emergency 125VDC battery system and performs cleaning and inspections on plant control cabinets and switchgear on a time available basis.

3.7 Review of manning

This review of manning has been divided in a review of current staffing and contracted services.

3.7.1 Current staffing

The EI&C department is officially supervised by the Maintenance Lead, but due to the complex nature of the tasks performed by the EI&C technicians, they self prioritize the work. The Maintenance Lead has a mechanical maintenance background and would be better suited to the supervision of the mechanical maintenance technicians. The addition of an EI&C supervisor would greatly enhance the department.

Currently, no long-range planning is being performed with respect to major maintenance and overhauls. The current practice is to run equipment to failure before an overhaul will be performed. Due to funding limitations, the CHPP is unable to establish an effective preventative maintenance program. Plant Management states that the staff understands the need for a preventative maintenance system and is capable of implementing a system if the effort were properly funded (Personal communication with Pat Driscoll and Mike Meeks). Table 4 lists current manning levels for the maintenance department.

Table 4. Current manning vs. authorized manning.

Position	Current	Authorized	Understaffing
EI&C Technician	3	5	2
Mechanical Technician	6	6	0
Lead Maintenance Tech	1	1	0

Table 5. Recommended manning additions.

Title	Number	Currently Authorized
Maintenance Manager/ Planner	1	No
EI&C Supervisor	1	No
EI&C Technicians	2	Yes, but not filled
Mechanical Maintenance Technicians	2	No

The authorized staffing levels are inadequate to perform all necessary work that will be required with a preventative maintenance program. Table 5 details manning recommendations. The EI&C department is undermanned by two technicians, based on authorized vs. actual staffing levels. The quality of work performed by the EI&C technicians has suffered due to that shortage. The lack of supervision is also negatively impacting both the quality and quantity of work being performed by the EI&C technicians. All major maintenance and overhaul work is subcontracted to qualified vendors. The lack of tracking of maintenance issues and lack of pre-planning of outages and overhauls has also had a negative impact on the condition of the equipment. For example, an operator relayed information to the evaluation team about a temperature input to the Instrumentation and Control system for one of the bearings on STG-5. The input had failed prior to the turbine overhaul in 2002. The problem was not repaired during the overhaul and still had not been corrected by March 2006 (Personal communication with operator).

3.7.2 Contracted services

Large and specialty maintenance actions are contracted to outside service providers. The 1995 ZBA Non-Destructive Evaluation (NDE) study is an example of large maintenance being awarded to outside contractors, because of the size and complexity of the work. The lack of records made thorough evaluation of this area impossible.

3.8 The Army's TM 5-650 program

The Army already has a simple program that is available for implementation at every CHPP in the Army inventory published in Technical Manual (TM) 5-650, *Repairs and Utilities: Central Boiler Plants* chapter 5. this preventive maintenance program relies on periodic maintenance of equipment to extend equipment life and increase reliability. (Appendix C to the TM contains the procedure.) The program provides an Army standard form (DA 4177) to record the applicable preventative maintenance actions for each piece of equipment on one side. The other side of the form contains space to record the dates each item was performed and by whom. These forms allow for the tracking of each maintenance action and provides for a level of accountability since the person performing the maintenance action is recorded. An example of a completed DA 4177 card is found in Appendix C on page 5-4. The procedure also provides recommended maintenance actions for various pieces of equipment throughout the central heating plant. The system relies on inspections to detect problems before they cause a forced outage, but does not deal with predictive functions at all. The current program at the plant is similar to this, but is not as extensive or formalized. The lack of a written procedure precludes having any accountability in the system. Accountability is an essential element to properly manage any program.

3.9 Summary of issues

Outlined below is a summary of issues related to this task and other issues not directly related to the task.

3.9.1 Summary of issues

The following list summarizes the major issues with the current maintenance system:

1. The existing maintenance system is solely reactive.
2. There is no written procedure documenting the maintenance program implementation. The lack of a formal written procedure hinders the maintenance of equipment by not standardizing how items are reported, tracked, and scheduled.
3. Maintenance logs do not have a formal tracking system.
4. Training of maintenance staff is lacking.
5. There is a general lack of records for maintenance activities.
6. Access to equipment OEM manuals and drawings needs to be improved. In fact, their very existence needs to be communicated.
7. No formal maintenance budget exists.
8. There is limited long range maintenance planning.

3.9.2 Summary of issues not related to study

The following list summarizes the issues that the study team observed during the site visit, but that are not directly related to this study:

1. Safety Program is lacking.
2. Plant Operations needs a formal Training and Qualification Program.

4 New Technologies

The chapter describes new technologies (diagnostic tools) that are required for, or will greatly enhance, the implementation of the recommended RCM program. The following sections discuss the following new technologies:

- Computerized Maintenance Management System (CMMS)
- Thermal Imaging Program
- Vibration Analysis Program
- Oil Analysis Program
- Non-Destructive Evaluation (NDE) Program.

In addition, a leak detection technology is described as a way to improve the performance monitoring of the CHPP baghouse, and to ensure its ability to meet environmental requirements.

4.1 Computerized maintenance management system (CMMS)

Computerized Maintenance Management Systems (CMMS) are computerized systems used to assist with the effective and efficient management of maintenance activities through the application of computer technology. A CMMS generally includes elements such as a computerized Work Order system, as well as facilities for scheduling Routine Maintenance Tasks, and recording and storing Standard Jobs, Bills of Materials and Applications Parts Lists, equipment and maintenance histories as well as numerous other features. CMMS have many different modules and functions; however, some are absolutely necessary for the proper implementation of any maintenance program.

The Work Order system is used to issue work actions, both preventative and reactive, to technicians. It provides a way to track that work through completion and then to store information gained from the action. That information can in turn be applied to make decisions on equipment disposition, manning requirements, and maintenance system improvements.

Maintenance action scheduling allows the user to define specific time periods between maintenance actions to allow for the automatic scheduling.

The use of this function requires the implementation of the system database including all equipment and maintenance actions. Inputting all the required data into the CMMS is a labor intensive task that will require one individual to spearhead. Often CMMS companies can provide an on-site consultant to perform that task for an additional charge.

A CMMS with a properly populated database has many advantages. It could allow the work cost estimates to be based on historical data as well as RFQs supplied by vendors. It could also allow failure analysis of equipment by equipment class, parts replaced, and specific manufacturer. Safety and lock out / tag out information can be tied to facility and even specific equipment. Some software packages can tie other electronic data to specific equipment including photos, drawings, procedures, and any other electronic document.

There are many different CMMS packages on the market today. They all have different capabilities and weaknesses. The evaluation of different products for use at the CHPP should include a team including representatives from the CHPP management and maintenance teams. CERL previously authored a study in September 1994 that provided selection criteria for a CMMS (DPSI 2007). These criteria are still valid and are:

- scheduling maintenance actions
- printing work orders
- logging work orders
- inventory parts
- inventory labor
- print maintenance reports.

In addition, the selected CMMS should, ideally, be able to link with the Army's Integrated Facilities System (IFS-M). This would allow data that is entered into the IFS-M to be automatically entered into the CMMS. This would help reduce data entry requirements, by avoiding duplication of effort. Two CMMS software packages are mentioned here only as references. Maximo® is a software package widely used in the power industry. Created and offered by MRO Software, it is a powerful tool that is capable of performing many functions including the ones mentioned above. However it is primarily designed to help manage the maintenance, budget, and purchasing for multiple installations (MRO software 2007). It is an expensive platform, which, while powerful, may not provide a cost effective solution at the CHPP. DPSI offers a software package iMaint® that is currently in use at the University of Illinois CHPP (Vavrin 2 June 2006). It is also a powerful tool and offers all the features mentioned in the list above. It appears to have a user friendly interface and intuitive menus (DPSI 2007). Further information on these two products is accessible through URLs:

- Maximo® http://www.mro.com/corporate/mrosolutions/index.php,
- iMaint® http://www.dpsi.com/products/overview.asp?prod=iMaint&sec=Overview.

Many products are available that can provide the functions required by the CHPP. It is recommended that as a follow on task a team be developed to investigate the most cost effective solution for use at the CHPP.

The cost of implementing a CMMS will vary depending on the solution chosen. However, costs must be taken into account for the database entry and research that will be required no matter what software is chosen. It takes approximately 1 work-year to populate the database for plants similarly sized to the CHPP. Table 6 lists cost estimate to license, install, train personnel and populate the database. Ongoing costs, which are detailed in the 25-year budget, include license renewals, updates, continuing training and database management. Computer hardware is not considered in this estimate. Once the CMMS software package is chosen then an analysis of the current computer system at the installation needs to be conducted to determine if it is adequate.

Table 6. CMMS implementation costs.

Item	Price (Each)	Number	Total
Training (On-Site)	$12,000	8 Technicians	$12,000
CMMS Software	$20,000	1	$20,000
Consultant	$68,000	1	$68,000
Total			$100,000

4.2 Thermal imaging program hardware

The use of thermal imaging equipment to evaluate the status of equipment is a proven method of determining if there are failures “waiting to happen” in the equipment. Hot bearings, wear points, poor electrical connections, and overloaded motors can all be detected. The cost savings in the use of thermal imaging equipment is the repair of equipment before a catastrophic failure occurs. For example, if a high resistance connection develops in the main plant switchgear, due to bus fasteners loosening over time, the results under heavy load conditions could be a major switchgear fire. A thermal imaging camera scan could locate the bad connection and repairs could be made before such a failure occurred. The equipment required is an infrared camera. Many contractors specialize in the use of this equipment and may have better quality equipment than would be fiscally feasible for Fort Wainwright to purchase. An evaluation of local contractors would need to be completed and a cost benefit analysis performed comparing the case of purchasing equipment and training staff to the case of retaining a local contractor to perform the studies. Table 7 lists cost information for the initial investment in equipment and training. Recurring costs are presented in the 25-year maintenance budget and include off site calibration and ongoing training.

Table 7. In-house thermal imaging implementation costs.

Item	Price (Each)	Number	Total
Training	$1500 plus travel	4 technicians	$6,000 plus travel
Thermal imaging camera	$6750	2	$13,500
Total			*$19,500 plus travel*

4.3 Vibration analysis program

All rotating equipment vibrates; vibration monitoring converts this vibration into an electrical signal that can be analyzed to determine if there are any problems. Vibration analysis can have a large return on investment. A study performed on the City of Houston's wastewater treatment department showed a return of $3.50 on every dollar invested, not to mention the potential for increased reliability (Levitt 2003). It is likely that the CHPP would receive similar savings by correcting problems before they result in catastrophic failure. For example, repairing bearing problems in motors before a catastrophic failure occurs. The turbine generators currently have a Bentley-Nevada real time vibration monitoring system installed for the bearings. This system inputs directly into the Westinghouse DCS and provides input for alarms. The data is currently not used to figure long-term trends for the equipment and therefore the full benefits of the system are not being captured. Vibration analysis can also help with other pieces of equipment. All rotating equipment can benefit from the use of vibration analysis to predict failures ranging from mechanical misalignment and gear wear to impending gear and bearing failure. Table 8 lists the initial investment in equipment and training for a vibration analysis program. The table below provides cost information for the initial investment in equipment and training. Recurring costs are presented in the 25-year maintenance budget and include off site calibration and ongoing training.

Table 8. Cost for vibration program implementation.

Item	Price (Each)	Number	Total
Training	$1,500 plus travel	4 technicians	$6,000 plus travel
Vibration analyzer	$4,000	2	$8,000
expert software	$10,000	1	$10,000
Total			*$24,000 plus travel-*

4.4 Oil analysis program

Proper care of the hydraulic and lubricating oil in equipment is necessary for the optimal performance of that equipment. The introduction of microscopic or dissolved contaminants can result in loss of functional life. No equipment is required to be purchased for this program. The oil should be sent to a qualified laboratory that specializes in the types of tests required for the different equipment. The manufacturer's recommended testing should be used in creation of this program. Table 9 lists representative sampling frequencies for various pieces of equipment, based on information obtained from the website for POLARIS Laboratories (2007). Tables 10 and 11, respectively, list oil analysis laboratories and cost estimates for offsite oil analysis.

Table 9. Sampling frequencies for various equipment types.

Equipment Type	Sampling Interval Normal / Intermittent Use	Sampling Location
Diesel engines	Quarterly (just prior to oil drain)	Through dipstick retaining tube or sampling valve installed in filter return
Hydraulics	Quarterly (just prior to oil drain)	Through oil fill port of system reservoir at mid-level
Steam turbines	Quarterly	Through sample valve installed upstream of the filter on the return line or out of the system reservoir
Gas/air compressors	Quarterly	Through sample valve installed upstream of the filter on the return line or out of the system reservoir
Gear and bearing systems	Quarterly	Through petcock valve at exit of each gear or bearing set or through system reserve

Table 10. Oil analysis laboratories.

Company	Address	Phone	Website
Polaris Laboratories, LLC	7898 Zionsville Road Indianapolis, IN 46268-2177	877-808-3750	http://www.polarislabs1.com/
Analysts, Inc.	2910 Ford Street Oakland, CA 94601	800-424-0099	http://www.analystsinc.com/
Herguth Laboratories, Inc.	101 Corporate Place, Vallejo , CA 94590-6968	1-888-437-4884	http://www.herguth.com/

Table 11. Oil analysis cost estimate.

Equipment	Number	Annual Cost
Steam Turbines	4	$5,700.00
Diesel Engine	1	$200.00
Air Compressors	4	$790.00
Gear Boxes	12 (estimate)	$2,360.00
Hydraulic Units	12	$2,360.00
Total Annual Cost		$11,410.00

4.5 Non-destructive evaluation (NDE)

Many of the previous reports on the condition of the equipment at the Fort Wainwright CHPP recommend an aggressive NDE program to maintain reliability of mechanical systems. In the past severe problems in the piping systems of the CHPP, as evidenced in the report from ZBA Engineering from 1995, have been discovered using NDE techniques. Severe corrosion in the piping to deaerators was discovered by these tests. There are many different technologies available to test pressure bearing elements for problems before they arise. It is beyond the scope of this document to give a complete explanation and evaluation of each individual technology. The technology being recommended is based on operating experience and technologies in use with other operations and maintenance clients. The use of this technology requires suitably trained technicians and the appropriate test equipment. It is recommended that outside contractors be used to perform these tests for large scale evaluations. The cost of equipment and certifications would be prohibitively expensive. Smaller evaluations, such as the tubes in one boiler during an outage can be performed by the maintenance staff. The following sections describe three common types of NDE: Ultrasonics, Eddy Current, and Radiography.

4.5.1 Ultrasonic inspection

Ultrasonic inspection uses sound waves above the range of human hearing to detect cracks and flaws in welds and other metals. Ultrasonic waves will echo from a surface whether that surface is due to a discontinuity or is the opposite surface of the material. The difference in time the echo takes to return determines the distance the flaw is from the probe. A small unit that is in general use in the industry is the KrautKramer CL5 manufactured by GE. It is easy to use and can be used for tubing thickness checks on a small scale during outages. The cost is approximately $3000 for the unit and an appropriate probe. An outside contractor should be used to perform testing on a large scale for example a total mapping of boiler tubes. The cost of an outside contractor performing large scale inspections is included in the cost for the boiler maintenance. Table 12 lists cost information for the initial investment in equipment and training for small scale evaluations. Recurring costs are presented in the 25-year maintenance budget and include off site calibration and ongoing training.

Table 12. In-house ultrasonic inspection implementation costs.

Item	Price (Each)	Number	Total
Training	$1,500 plus Travel	4 Technicians	$6,000 plus Travel
Ultrasonic Thickness Meter	$3,000	2	$6,000
Total			$12,000 plus Travel

4.5.2 Eddy current testing

A test coil carrying alternating current of various frequencies induces eddy currents into the test material. Eddy currents will flow around discontinuities becoming compressed, delayed, or weakened. The electrical reaction is amplified and recorded on the test equipment. The technique works well with a wide range of ferrous materials, but has very poor response to nonferrous materials. It is recommended that an outside contractor be used for eddy current testing due to the length of time it takes to perform a study and the cost of equipment and training. The cost of an outside contractor performing this test is estimated to be $12,400 per year in constant 2006 dollars and is included in the budget.

4.5.3 Radiography

Radiography is the use of radioactive material to produce high energy gamma rays to pass through the test material and strike film. The amount of gamma rays absorbed by the material is directly proportional to the density and amount of material between the source and the film. The more gamma rays that strike the film the darker the film gets. Voids, thinning walls, and other abnormalities will show up as dark spots compared to the continuous material that absorbs more of the gamma rays. This type of testing requires very specific training and materials and is only performed by specialized contractors. This type of inspection should be performed every 10 years on major system piping and components. The cost of these inspections is estimated to be $18,250 per year in constant 2006 dollars and is included in the budget items for each system.

4.6 Environmental concerns

4.6.1 Baghouse leak detection and performance measurement improvements

The CHPP controls particulate matter emissions using a baghouse. The Title V operating permit for Fort Wainwright requires that baghouse keep PM10 emissions below 0.05 grains per dry standard cu ft averaged over 3 hrs. When the operating permit is renewed, a draft compliance assurance monitoring plan (CAM) will be submitted to the Alaska air regulators. The CAM plan will cover performance measurements of the baghouse that will help ensure continuous compliance with the 0.05 grains per dry standard cu ft concentration requirement. The current version of the draft CAM plan recommends that measurements of pressure drop across the baghouse and opacity downstream of the baghouse be used as performance indicators. Of these two measurements, opacity is the more sensitive indicator of deteriorating baghouse performance, but the inherent accuracy limitations and allowable drift can reduce this measurement's usefulness in determining excursions or exceedances of the particulate matter concentration requirement.

The draft CAM plan recommends that opacity readings between 10 and 20 percent be considered an excursion and opacity readings above 20 percent an exceedance. These limits are based on a 1996 source test of the boilers where visual determinations of opacity were made during the course of the test. An average of these tests results shows that 10 percent opacity corresponded to the 0.05 grains per dry standard cu ft concentration requirement. More recent source test results are less useful because the baghouse kept the concentrations and opacity readings very low. The recommended opacity ranges are somewhat liberal in that the 1996 source test data suggests that readings of opacity between 10 and 20 percent would indicate concentration values exceeding the permitted concentration standard. The 1996 source test data is also somewhat uncertain because EPA Method 9 was used to obtain opacity readings. Method 9 is based on human observation of plume opacities and is therefore very subjective. The opacity readings are also only recorded in 5 percent increments and therefore a 10 percent reading could indicate actual opacities between 7.5 and 12.5 percent. Because of these uncertainties, it is possible that Alaska air regulators could require lower opacity excursion and exceedance thresholds.

It is fairly well accepted that continuous opacity monitoring systems (COMS) like the one used at the CHPP have uncertainties associated with readings below 10 percent. The EPA has published performance specifications for COMS that cast doubt on COMS ability to accurately measure low opacity values. Performance Specification 1 (PS-1) —Specifications and Test Procedures for Continuous Opacity Monitoring Systems in Stationary Sources found in 40 CFR 60 Appendix B includes the following statements related to opacity measurements less than 10 percent:

> The measurement uncertainties associated with COMS data result from several design and performance factors including limitations on the availability of calibration attenuators for opacities less than about 6 percent (3 percent for single-pass instruments), calibration error tolerances, zero and upscale drift tolerances, and allowance for dust compensation that are significant relative to low opacity levels.

The EPA performance specifications for COMS are based on the American Society of Testing and Materials (ASTM) D6216-98 "Standard Practices for Opacity Monitor Manufacturers to Certify Conformance with Design and Performance Specifications." In the August 10, 200 Federal Register entry for the promulgation of amendments to PS-1, the preamble contains the following statements:

> The Task Group chairperson for this method indicated in his comments on the supplemental proposal that the calibration error specification of

> ±3 percent opacity, the zero and upscale drift specifications of ±2 percent opacity, and the PS-1 requirements to adjust monitors when drift exceeds two times the specification (i.e., ±4 percent opacity) are inappropriate for monitoring an opacity standard below 10 percent. Special calibration attenuators and calibration techniques, not yet available on a broad basis, are needed for cases where the opacity standard is below 10 percent. He noted that imprecision allowances of this magnitude create excessive uncertainty for establishing compliance with a low opacity limit.

The uncertainty expressed by regulators about low opacity measurements made with COMS also leads to uncertainty over the ability of the CHPP COMS to determine continuous compliance with the PM10 concentration limit.

4.6.2 Baghouse leak detectors based on triboelectric effect

A measurement system that was more accurate for low PM10 concentration readings would improve the reliability of determining compliance with the PM10 concentration requirement. Baghouse bag leak detectors based on what is known as the triboelectric effect have been shown to be accurate at these low PM10 concentration readings. When two solids come into contact, an electrical charge is transferred between the two bodies. This charge transfer is known as the triboelectric principle, or contact electrification. As particles in a gas stream collide with a sensor placed in the stream, the charge transfer generates a current that can be measured using triboelectric monitoring equipment. The current signal produced by the triboelectric effect is generally proportional to the particulate mass flow and triboelectric monitoring systems have been shown to detect baseline emissions as low as 0.1 mg/dscm (0.00005 gr/dscf) (USEPA September 1997). Figure 12 shows a typical monitoring schematic for these systems.

Since the triboelectric effect monitors have such high sensitivity, they would have a much greater chance of detecting deterioration of baghouse performance. There are many manufacturers of these monitors and the system could be easily installed at the CHPP. The new bag leak detector would not be a replacement for the COMS since the COMS provides a direct measure of opacity and is needed to show compliance with the 20 percent opacity requirement found in the Title V operating permit.

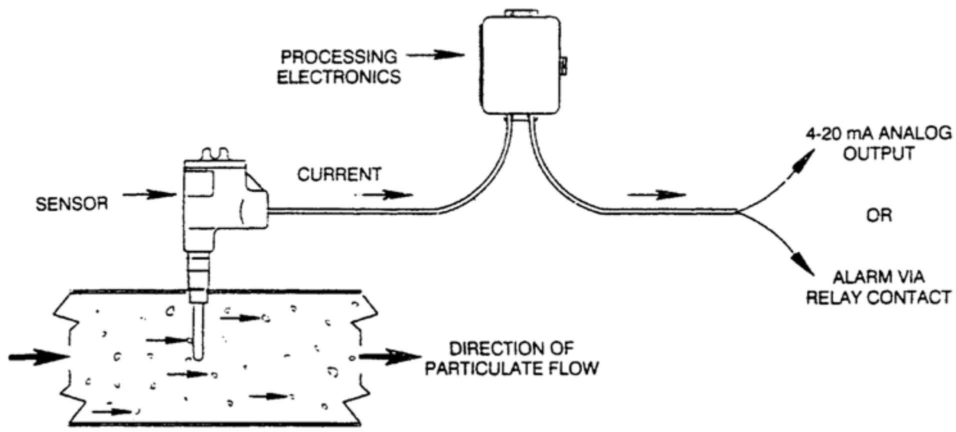

Figure 12. Monitoring system schematic (Source: GEA Power Cooling Systems September 1996).

The installation of this type of bag leak detector would show a good faith effort to maintain continuous compliance with the PM10 concentration requirement and help to maintain the trust that has been built with regulators in the last few years.

4.7 Prioritization of new technologies

The technologies described in this chapter, will provide the greatest benefit if used together within the framework of a formalized RCM system. The ideal implementation of these technologies would be a completely parallel system adoption. This is generally not feasible due to time and manpower restraints. Therefore a prioritized implementation of the CMMS or at least initiation of the implementation is recommended. This critical piece of technology is the centerpiece of any maintenance system. It provides scheduling, work tracking and data collection services. Next, the implementation of the Vibration Analysis program will provide the best immediate return on money spent. The results can instantly be put into use to facilitate repairs and prevent impending failures. The Thermal Imaging program will also provide the facility with immediate returns on the investment by discovering problems with the potential of causing fires and severe equipment damage. The Thermal Imaging equipment can also be used to find hot spots to help extinguish smoldering embers should a fire occur. The Oil Analysis program will provide valuable information in the up keep of the plant and is easy to implement. While it may not provide immediate benefits, the information gathered will be invaluable for the maintenance of the equipment. The NDE program is listed last because it is to be implemented with the entire maintenance program. This is not to say that NDE is the least important technology. In fact, all of these technologies are needed to maintain the reliability required of the CHPP.

6.7 Estimated maintenance program costs with recommended technologies

The estimated budget presented in Table 13 details the cost associated with implementing and supporting the various new technologies at the CHPP. The implementation costs from the previous tables above are reflected in the year 2006 column of Table 13. Subsequent years detail the ongoing costs of supporting the system including: off site calibration of test equipment, continuing training, and replacement cost of equipment at the end of equipment life. The 25-year total for implementation and ongoing support costs come to $1,164,000 in constant 2006 dollars.

Table 13. Estimated maintenance program cost for new technologies ($2006).

Year	Estimated Maintenance Program Cost, (2006 dollars)												
	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
New Technology													
Computerized Maintenance Management System	100,000	20,000	20,000	20,000	20,000	20,000	20,000	20,000	20,000	20,000	20,000	20,000	20,000
Vibration Analysis Systems	24,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	24,000	2,000	2,000
Thermal Imaging	20,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	20,000	2,000	2,000
Ultrasonic	12,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	12,000	2,000	2,000
Oil Analysis	11,000	11,000	11,000	11,000	11,000	11,000	11,000	11,000	11,000	11,000	11,000	11,000	11,000
Subtotal New Technology	167,000	37,000	37,000	37,000	37,000	37,000	37,000	37,000	37,000	37,000	87,000	37,000	37,000

Year	Estimated Maintenance Program Cost, (2006 dollars)												
	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Total
New Technology													
Computerized Maintenance Management System	20,000	20,000	20,000	20,000	20,000	20,000	20,000	20,000	20,000	20,000	20,000	20,000	580,000
Vibration Analysis Systems	2,000	2,000	2,000	2,000	2,000	2,000	2,000	24,000	2,000	2,000	2,000	2,000	116,000
Thermal Imaging	2,000	2,000	2,000	2,000	2,000	2,000	2,000	20,000	2,000	2,000	2,000	2,000	103,000
Ultrasonic	2,000	2,000	2,000	2,000	2,000	2,000	2,000	12,000	2,000	2,000	2,000	2,000	80,000
Oil Analysis	11,000	11,000	11,000	11,000	11,000	11,000	11,000	11,000	11,000	11,000	11,000	11,000	285,000
Subtotal New Technology	37,000	37,000	37,000	37,000	37,000	37,000	37,000	87,000	37,000	37,000	37,000	37,000	1,164,000

Notes: (1) Rounding. The above values might not necessary sum up to the indicated totals due to rounding.
(2) The accuracy of the estimate is + or – 30 to 35 percent.

5 Overview of PM Budget

A forecast of the comprehensive budget estimate for the preventative maintenance activities for the CHPP for the period of 2006 through 2030 has been developed. This budget includes the new technologies presented in Chapter 6. The budget is presented in future dollars, which represent the base year estimates listed in Table ES2 (p vi) with escalation factors applied for labor and materials. Material costs have been escalated at an annual rate of 2.09 percent and labor has been escalated at an annual rate of 2.43 percent. These values are consistent with the Department of Energy's Federal Energy Management Program (FEMP) guidelines.

Table 14 lists the factors that have been applied to the baseline 2006 costs that incorporate the annual escalation rates. The factors have been applied to the baseline to estimate the future costs of the preventative maintenance budget.

Table 15 lists the future budgets estimated for the preventative maintenance budget for the CHPP for the period of 2006 through 2030. This table is intended to be used for establishing the future annual budgets for the preventative maintenance program for the CHPP at FWA.

Table 14. Annual factors for future costs.

Year	Material Factor	Labor Factor
2006	1.0000	1.0000
2007	1.0209	1.0243
2008	1.0422	1.0492
2009	1.0640	1.0747
2010	1.0863	1.1008
2011	1.1090	1.1276
2012	1.1321	1.1549
2013	1.1558	1.1830
2014	1.1800	1.2118
2015	1.2046	1.2412
2016	1.2298	1.2714
2017	1.2555	1.3023
2018	1.2817	1.3339
2019	1.3085	1.3663
2020	1.3359	1.3995
2021	1.3638	1.4335
2022	1.3923	1.4684
2023	1.4214	1.5040
2024	1.4511	1.5406
2025	1.4814	1.5780
2026	1.5124	1.6164
2027	1.5440	1.6557
2028	1.5763	1.6959
2029	1.6092	1.7371
2030	1.6428	1.7793

Table 15. Preventative maintenance budget – future costs.

	Estimated Maintenance Program Cost, (Future Cost - Estimated to Year of Occuance)												
Year	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Boilers 1 through 6	1,500,000	1,530,000	1,570,000	1,600,000	1,640,000	1,470,000	1,540,000	1,620,000	1,700,000	1,780,000	1,870,000	1,960,000	2,060,000
Steam Turbine													
ST 1	200,000	102,000	130,000	137,000	1,232,000	292,000	160,000	168,000	177,000	186,000	196,000	206,000	217,000
ST 3	200,000	102,000	130,000	137,000	144,000	182,000	160,000	168,000	177,000	186,000	196,000	206,000	217,000
ST 4	200,000	102,000	130,000	1,202,000	144,000	182,000	160,000	168,000	177,000	186,000	196,000	206,000	217,000
ST 5	200,000	102,000	1,173,000	137,000	144,000	152,000	160,000	168,000	177,000	186,000	196,000	206,000	217,000
Subtotal Steam Turbine	800,000	409,000	1,565,000	1,614,000	1,666,000	608,000	640,000	673,000	708,000	745,000	784,000	825,000	869,000
Balance of Plant													
Coal Handling System	173,000	177,000	182,000	186,000	190,000	197,000	202,000	206,000	211,000	216,000	216,000	221,000	227,000
Ash System (including Baghouse/ID Fan/Env Cont)	161,000	164,000	168,000	172,000	176,000	132,000	135,000	138,000	141,000	145,000	136,000	139,000	142,000
Steam Piping System	107,000	109,000	111,000	114,000	116,000	55,000	56,000	58,000	59,000	60,000	61,000	63,000	64,000
Feedwater / Condensate System	63,000	64,000	66,000	67,000	69,000	81,000	83,000	85,000	87,000	89,000	91,000	93,000	95,000
Cooling System	187,000	191,000	195,000	200,000	204,000	50,000	51,000	52,000	53,000	54,000	38,000	39,000	39,000
Water Treatment System	98,000	100,000	103,000	105,000	107,000	38,000	39,000	40,000	40,000	41,000	40,000	41,000	42,000
Instrumentation / Control Systems	99,000	102,000	105,000	108,000	111,000	36,000	38,000	40,000	42,000	44,000	134,000	139,000	143,000
Electrical Distribution System	115,000	119,000	123,000	128,000	132,000	59,000	62,000	65,000	69,000	72,000	114,000	119,000	124,000
Maintenance Shop Equipment, Small Tools, etc.	15,000	16,000	17,000	17,000	18,000	19,000	20,000	21,000	22,000	24,000	25,000	26,000	27,000
Maintenance Consumables	40,000	42,000	44,000	47,000	49,000	51,000	54,000	57,000	60,000	63,000	66,000	70,000	73,000
Subtotal Balance of Plant	1,060,000	1,090,000	1,110,000	1,140,000	1,170,000	720,000	740,000	760,000	780,000	810,000	920,000	950,000	980,000
New Technology													
Computerized Maintenance Management System	100,000	20,000	21,000	21,000	22,000	22,000	23,000	23,000	24,000	24,000	25,000	25,000	26,000
Vibration Analysis Systems	24,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	30,000	3,000	3,000
Thermal Imaging	20,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	24,000	3,000	3,000
Ultrasonic	12,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	15,000	3,000	3,000
Oil Analysis	11,000	12,000	12,000	12,000	12,000	13,000	13,000	13,000	13,000	14,000	14,000	14,000	15,000
Subtotal New Technology	167,000	38,000	39,000	40,000	41,000	41,000	42,000	43,000	44,000	45,000	107,000	47,000	48,000
Subtotal CHPP Bare Erected Costs	3,530,000	3,070,000	4,280,000	4,400,000	4,520,000	2,840,000	2,960,000	3,090,000	3,230,000	3,380,000	3,680,000	3,780,000	3,950,000
Owner's Costs (Engineering @ 5%)	176,000	153,000	214,000	220,000	226,000	142,000	148,000	155,000	162,000	169,000	184,000	189,000	198,000
Subtotal Bare Erected Costs and Owner's Costs	3,700,000	3,220,000	4,500,000	4,620,000	4,740,000	2,980,000	3,110,000	3,250,000	3,400,000	3,550,000	3,870,000	3,970,000	4,150,000
Project Contingency	930,000	800,000	1,120,000	1,150,000	1,190,000	890,000	930,000	970,000	1,020,000	1,060,000	1,350,000	1,390,000	1,450,000
Total Plant Maintenance Cost (excluding Staffing)	4,630,000	4,020,000	5,620,000	5,770,000	5,930,000	3,870,000	4,040,000	4,220,000	4,410,000	4,610,000	5,220,000	5,360,000	5,600,000
Total Plant Labor Cost (Recommended Staffing)	1,100,000	1,130,000	1,150,000	1,180,000	1,210,000	1,240,000	1,270,000	1,300,000	1,330,000	1,360,000	1,400,000	1,430,000	1,470,000
Total Plant Cost	5,730,000	5,150,000	6,780,000	6,950,000	7,140,000	5,110,000	5,310,000	5,520,000	5,750,000	5,980,000	6,620,000	6,790,000	7,070,000

Year		Estimated Maintenance Program Cost, (2006 dollars)												
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Total
Boilers 1 through 6	2,060,000	2,160,000	2,270,000	2,240,000	2,360,000	2,480,000	2,610,000	2,740,000	2,890,000	3,040,000	3,190,000	3,360,000	3,530,000	54,720,000
Steam Turbine														
ST 1	217,000	228,000	240,000	253,000	266,000	280,000	295,000	310,000	326,000	344,000	361,000	380,000	400,000	6,951,000
ST 3	217,000	228,000	240,000	253,000	266,000	280,000	295,000	310,000	326,000	344,000	361,000	380,000	400,000	5,863,000
ST 4	217,000	228,000	240,000	253,000	266,000	280,000	295,000	310,000	326,000	344,000	361,000	380,000	400,000	6,928,000
ST 5	217,000	228,000	240,000	253,000	266,000	280,000	295,000	310,000	326,000	344,000	361,000	380,000	400,000	6,906,000
Subtotal Steam Turbine	869,000	914,000	962,000	1,012,000	1,065,000	1,121,000	1,179,000	1,241,000	1,306,000	1,374,000	1,446,000	1,521,000	1,601,000	26,648,000
Balance of Plant														
Coal Handling System	227,000	232,000	237,000	248,000	254,000	259,000	265,000	272,000	278,000	284,000	291,000	298,000	305,000	5,827,000
Ash System (including Baghouse/ID Fan/Env Cont)	142,000	145,000	149,000	152,000	156,000	159,000	163,000	167,000	170,000	174,000	178,000	182,000	187,000	3,933,000
Steam Piping System	64,000	66,000	67,000	64,000	65,000	67,000	68,000	70,000	74,000	76,000	77,000	79,000	81,000	1,885,000
Feedwater / Condensate System	95,000	97,000	99,000	68,000	70,000	71,000	73,000	74,000	120,000	122,000	125,000	128,000	131,000	2,209,000
Cooling System	39,000	40,000	41,000	63,000	64,000	66,000	67,000	69,000	103,000	105,000	107,000	110,000	112,000	2,301,000
Water Treatment System	42,000	43,000	43,000	29,000	29,000	30,000	30,000	31,000	68,000	70,000	71,000	73,000	75,000	1,426,000
Instrumentation / Control Systems	143,000	148,000	153,000	60,000	63,000	66,000	70,000	73,000	186,000	192,000	199,000	206,000	213,000	2,768,000
Electrical Distribution System	124,000	129,000	135,000	98,000	103,000	108,000	113,000	119,000	125,000	132,000	139,000	146,000	153,000	2,801,000
Maintenance Shop Equipment, Small Tools, etc.	27,000	29,000	30,000	32,000	34,000	35,000	37,000	39,000	41,000	43,000	45,000	48,000	50,000	731,000
Maintenance Consumables	73,000	77,000	81,000	85,000	89,000	94,000	99,000	104,000	109,000	115,000	121,000	127,000	134,000	1,950,000
Subtotal Balance of Plant	980,000	1,010,000	1,040,000	900,000	930,000	960,000	990,000	1,020,000	1,270,000	1,310,000	1,350,000	1,400,000	1,440,000	25,830,000
New Technology														
Computerized Maintenance Management System	26,000	26,000	27,000	27,000	28,000	28,000	29,000	30,000	30,000	31,000	32,000	32,000	33,000	728,000
Vibration Analysis Systems	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	36,000	3,000	3,000	3,000	3,000	147,000
Thermal Imaging	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	29,000	3,000	3,000	3,000	3,000	130,000
Ultrasonic	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	18,000	3,000	3,000	3,000	3,000	102,000
Oil Analysis	15,000	15,000	15,000	16,000	16,000	16,000	17,000	17,000	17,000	18,000	18,000	18,000	19,000	370,000
Subtotal New Technology	48,000	49,000	50,000	51,000	52,000	53,000	54,000	55,000	131,000	58,000	59,000	60,000	61,000	1,477,000
Subtotal CHPP Bare Erected Costs	3,950,000	4,130,000	4,320,000	4,200,000	4,400,000	4,610,000	4,830,000	5,060,000	5,600,000	5,780,000	6,050,000	6,340,000	6,640,000	108,670,000
Owner's Costs (Engineering @ 5%)	198,000	207,000	216,000	210,000	220,000	230,000	241,000	253,000	280,000	289,000	303,000	317,000	332,000	5,434,000
Subtotal Bare Erected Costs and Owner's Costs	4,150,000	4,340,000	4,530,000	4,410,000	4,620,000	4,840,000	5,070,000	5,310,000	5,880,000	6,070,000	6,360,000	6,650,000	6,970,000	114,110,000
Project Contingency	1,450,000	1,520,000	1,590,000	1,770,000	1,850,000	1,940,000	2,030,000	2,120,000	2,350,000	2,430,000	2,540,000	2,660,000	2,790,000	39,850,000
Total Plant Maintenance Cost (excluding Staffing)	5,600,000	5,860,000	6,120,000	6,180,000	6,470,000	6,780,000	7,100,000	7,440,000	8,230,000	8,500,000	8,900,000	9,320,000	9,760,000	153,960,000
Total Plant Labor Cost (Recommended Staffing)	1,470,000	1,500,000	1,540,000	1,580,000	1,610,000	1,650,000	1,690,000	1,730,000	1,780,000	1,820,000	1,860,000	1,910,000	1,960,000	37,200,000
Total Plant Cost	7,070,000	7,360,000	7,660,000	7,750,000	8,080,000	8,430,000	8,790,000	9,170,000	10,010,000	10,320,000	10,760,000	11,230,000	11,710,000	191,160,000

6 Results and Discussion

6.1 Reliability centered maintenance (RCM)

A Reliability Centered Maintenance (RCM) program contains the optimum mix of reactive, time-based, condition-based, and proactive maintenance practices. These principal maintenance strategies, rather than being applied independently, are integrated to take advantage of their respective strengths to maximize facility and equipment reliability while minimizing life-cycle costs. RCM is a system based approach that takes into account the overall function of the system rather than the individual parts of that system (Smith and Hinchcliffe 2004). The primary RCM principles emphasize a system that is:

- **Function Oriented.** RCM seeks to preserve system or equipment function.
- **System Focused.** RCM is more concerned with maintaining system function than with individual component function.
- **Reliability Centered**. RCM is not overly concerned with simple failure rate; it seeks to know the probability that failure will occur in each given operating age bracket of the system. The curves in Figure 13 represent seven different models of failure.

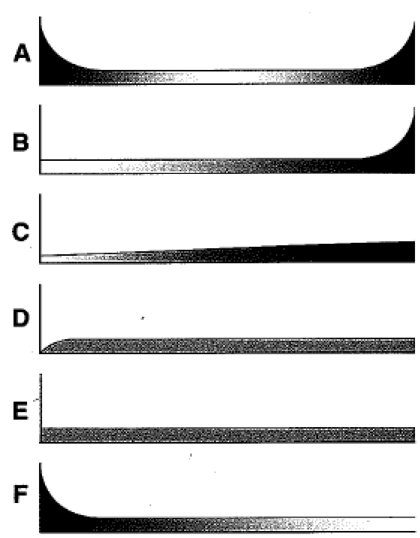

Figure 13. Lifetime failure curves.

Curve A shows the standard **"bathtub"** curve that represents an initial high failure rate (also known as infant mortality) followed by a constant failure rate. As the component ages and nears the end of its design life the failure rate increases again.

Curve B represents a **constant initial failure rate** and as the component ages and nears the **end of its design life** the rate increases.

Curve C shows a low initial failure rate followed by **a slow linear increase in failure rate** as the component ages.

Curve D shows **a rapidly increasing failure rate** during initial operations to **a steady state failure rate** during the rest of the design life of the component.

Curve E shows a steady failure rate throughout the life of the component.

Curve F represents **a high infant mortality** rapidly decreasing failure rate to a steady state rate over the rest of the component's life (Moubray 1997).

These many different modes of failure have led to the concept of mixing different maintenance philosophies and blending their strengths to minimize the likelihood of all the different failure modes cost effectively in a system that:

- *Acknowledges Design Limitations*. The RCM objective is to maintain the reliability of the equipment, recognizing that changes in reliability are a function of design as well as maintenance. Maintenance can, at best, only achieve and maintain the level of reliability that was provided for by design. However, RCM recognizes that maintenance feedback can improve on the original design. This is accomplished by reviewing maintenance and determining if changing materials, reconfiguration, or any other engineering changes can improve reliability.
- *Requires That Maintenance Tasks Be Applicable*. The tasks must address the failure mode and consider the failure mode characteristics.
- *Requires That Maintenance Tasks Be Effective*. The tasks must reduce the probability of failure and be cost-effective.

- *Acknowledges Four Types of Maintenance Tasks*: (1) reactive, (2) time-directed or preventive maintenance, (3) condition-directed or predictive maintenance, and (4) failure finding or functional testing. Time-directed tasks are scheduled when appropriate. Predictive tasks are performed to determine when conditions are appropriate to perform a particular task. For example, ultrasonic thickness measurement of boiler tubes shows when a tube needs to be plugged or a retubing is necessary. Failure-finding tasks detect hidden functions that are in danger of causing premature failure such as the failure of a low lube oil pressure trip sensor.
- *Is a "Living System."* RCM gathers data from the results achieved and feeds this data back to improve design and future maintenance. This feedback is an important part of the Proactive Maintenance element of the RCM program (MRO software 2007).

The implementation of a new RCM system will require the addition of new technologies, equipment, and skills to the existing plant. The addition of some kind of Computerized Maintenance Management System (CMMS) is paramount to the success of any maintenance program and doubly so for an RCM type program. The CMMS is the heart of any system with its ability to store, retrieve, and export vast amounts of data. It will allow the seamless tracking of reactive maintenance actions, the scheduling of time based items, and data storage for the condition based items (Bowman and Moshage September 1994). The data can be analyzed using any number of different tools to determine the statistical probability of failure for different pieces of equipment.

The installation of a secure plant wide computer network would greatly improve the efficiency of any added CMMS system. The adoption of other new technologies including Vibration Analysis, Thermal Imaging, and a real time data collection system to collect data directly from the Distributed Control System (DCS) will be required to perform the condition based portions of the program. These technologies will require the purchase of required diagnostic equipment and supporting computer software. Training of technicians and management in the use of this equipment will be critical to the success of the program. The implementation of the system will be labor intensive and require the commitment from management for the program to be successful.

During the implementation of the system, the plant personnel will still be repairing equipment that has been suffering from a lack of a maintenance program. This leads to an increased cost initially to implement the program. The cost of repairs will remain high until all of the major repairs have been made. This situation results in the misconception that it actually costs more money to operate with a maintenance program in place then it did when the plant was operating on a purely reactive basis. Costs will eventually come down, but reliability is the major benefit for the facility. RCM type systems have resulted in a 50 percent or more decrease in the breakdown rate of equipment (Smith and Hinchcliffe 2004). This does not necessarily translate directly into added reliability of the equipment. It means that maintenance issues are handled during scheduled outages that can be controlled by the CHPP. This can cascade into cost savings on acquiring needed spare parts or obtaining contractor services over a longer period of time instead of placing rush orders, which often have a price premium attached to them.

6.2 Estimated implementation schedule

The implementation plan will be discussed first in terms of items that are common to the whole plant and then will be discussed by items that are specific to each major system.

6.2.1 General implementation

The implementation of any new maintenance system is a large and complex task that requires careful planning and forethought. The implementation must be broken down into carefully considered and manageable steps. Infrastructure (i.e., new equipment), software, and tools need to be acquired first.

The easiest portion of the system to implement will be the “reactive maintenance” portion, since reactive maintenance forms the basis for current CHHP maintenance. The installation of the CMMS will allow the creation and tracking of work orders for reactive maintenance actions that will allow for better management and tracking of technician’s time, equipment downtime, the root cause of the problem, and reporting. Next, each piece of equipment will have to have its boundaries set, an evaluation performed, and a decision made as to what type of maintenance action will be performed for that piece of equipment. The types of failures and the results of each failure mode will be formulated for each piece of equipment. The results of this assessment and a logic tree (Figure 14) will be used to determine the type of maintenance action that will be used.

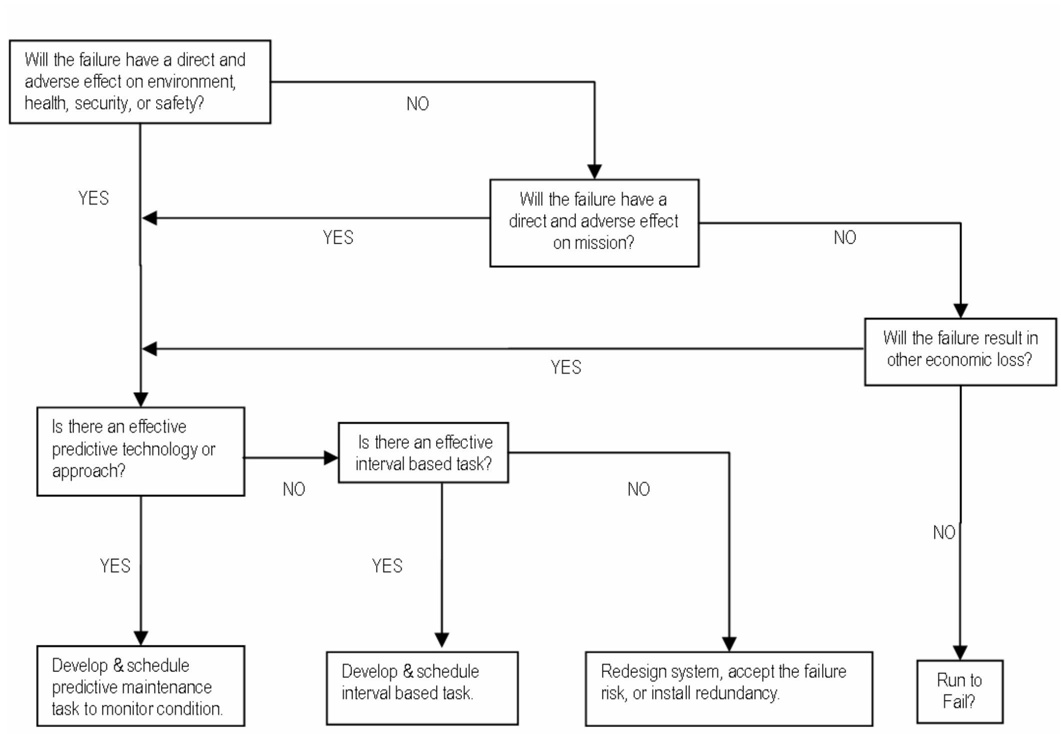

Figure 14. RCM logic tree.

The maintenance actions recommended below are not intended to be an exhaustive list, but to be used as a guide. These recommendations are based on past operating experience, judgment, and manufacturer's recommendations for similar systems.

Table 16 presents actions that are relevant to all the plant systems and are easier to breakout separately then include in the individual system tables.

Table 16. Plant wide maintenance actions.

Maintenance action	Periodicity	Type*	Notes
Radiographic Inspection	10 yrs	P	Perform a radiographic inspection of all major plant systems
All pumps	Annually	P	All pumps will be inspected for impellor wear, casing wear, shaft eccentricity, correct coupling and pump performance
Oil Sample Analysis	Semi-Annually	P	All equipment that uses oil in any way will have a sample taken and analyzed to ensure compliance with manufacturer's recommendations
All Motors, Pumps, Conveyors and Fans	Monthly	T	Lubricate all bearings
Vibratory Monitoring of all rotating equipment	Monthly	P	The plant will be broken down into six zones and each zone will be surveyed once a month. This is so the entire plant will be surveyed every six months
Thermal Imaging of all Plant Equipment	Monthly	P	The plant will be broken down into six zones and each zone will be imaged once a month. This is so the entire plant will be imaged every six months
All Electrical Boxes, Control Cabinets, and Switchgear Clean and Inspect	Monthly	T	The plant will be broken down into six zones and all electrical equipment in each zone will be cleaned and inspected each month. This is so all equipment will be cleaned and inspected every six months.
Piping and Weld Inspection	Monthly	P	The plant will be broken down into 12 zones and all process piping, welds and fittings in one zone will be inspected each month
Valve Exercising	Monthly	T	The plant will be broken down into six zones and all valves in one zone will be cycled monthly
Motor, Generator, and Distribution Insulation Resistance Checks	Monthly	P	The plant will be broken down into six zones and all motors in one zone will be tested each month so that all motors will be tested every six months
Belt Driven Equipment Checks	Monthly	T	The plant will be broken down into six zones and all belt driven equipment in a zone will be checked each month so that all equipment will be checked every six months
Turbine Lubricating Oil Sample Analysis	Monthly	P	All turbine lubricating oil will be sampled monthly and changed when required by sample analysis
Air Lubricator and Filter Inspection	Monthly	T	Drain and fill all Air Lubricators and filters
Clean and Inspect Suction Strainers	Monthly	T	Clean and inspect the suction strainer of all pumps
* T-Time based (Preventative) maintenance item, P-Predictive maintenance item, F-Failure finding maintenance item			

6.2.2 Schedule by system

This section presents information on the boiler, steam turbines, and the following major plant systems:

- feedwater system
- condensate system
- steam system
- coal handling system
- ash handling system
- cooling system
- water treatment system
- electrical system
- instrument and controls system.

The major maintenance actions and recommended periodic maintenance requirements will be presented in this section. The condition based requirements that may be needed will be addressed, but final determination of maintenance requirements will be performed with the equipment evaluations during system implementation.

6.2.2.1 Boilers

Table 17 details the annual operating hours for the 3-year period (2002 to 2004) for all six operating boilers. The hours of all boilers are within 20 percent of the average of all six. It is therefore assumed that all boilers have been operated a similar number of hours over their operating lives thus far and are in a similar state of repair.

Table 17. Three-year boiler operating hours.

Year	Boiler #3	Boiler #4	Boiler #5	Boiler #6	Boiler #7	Boiler #8	Average
2002	6326.9	7369.05	5664.7	3098.93	4053.87	7020.75	5589.033
2003	6895.7	3081.8	6368.9	6407.8	7245.7	2630.4	5438.4
2004	6757.1	5955.6	4658.1	4677.6	4214.0	3824.7	5014.5
Total	*19,979.6*	*16,406.5*	*16,691.7*	*14,184.3*	*15,513.6*	*13,475.9*	*16,041.9*

The maintenance actions recommended below are not intended to be an exhaustive list, but to be used as a guide. These recommendations are based on past operating experience, judgment, and manufacturer's recommendations for similar systems. Table 18 lists the recommended boiler maintenance schedule.

Table 18. Boiler recommended maintenance actions.

Maintenance action	Periodicity	Type*	Notes
Safety relief valves test	Annually	F	Test pressure at which valve lifts
Boiler inspection by regulatory agency	Annually	T	Inspection by the required regulatory agency to ASME standards
Boiler inspection	Semi-Annually	T	Check fastener tightness, boiler supports, setting for cracks, baffles, blowdown piping, boiler drain valves
Water wall tubes and headers ultrasonic inspection	Semi-Annually	P	Perform on one boiler semi-annually on a rotating basis.
Superheater tubes and headers ultrasonic inspection	Semi-Annually	P	Perform on one boiler semi-annually on a rotating basis.
Economizer tubes and headers ultrasonic inspection	Semi-Annually	P	Perform on one boiler semi-annually on a rotating basis.
Boiler refractory inspection	Semi-Annually	T	Perform on one boiler semi-annually on a rotating basis.
Steam and mud drums inspection and nde	Semi-Annually	P	Perform on one boiler semi-annually on a rotating basis.
Fd fans inspection	Semi- Annually	T	Perform on all Fans Visual Inspection of expansion joints, casing and blades. Ensure rotates freely.
Boiler grate drives lubrication	Semi- Annually	T	Oil chains and inspect for broken or deformed links
Casing	Semi-Annually	T	Inspect, repair as required
Boiler grate drives inspection	Monthly	T	Inspect seals, rails, bearings, and VFDs
Boiler coal spreader stoker inspection	Monthly	T	Inspect all mechanicals including underthrow feeder
Sootblower inspection	Monthly	T	Inspect all mechanicals including piping
Overfire air fans	Monthly	T	Inspect all mechanicals
Safety relief valves manual lift	Monthly	T	Use mechanical override device to open valve and blow material clear of seat
Water whistle test and inspect	Monthly	F	Inspect and Test repair as required
* T-Time based (Preventative) maintenance item, P-Predictive maintenance item, F-Failure finding maintenance item			

6.2.2.2 *Steam turbines*

The steam turbines will require periodic maintenance to maintain efficiency and reliability. Other maintenance will be required on the turbine support systems including oil analysis on the lubricating and control oil, lube oil pumps, governor equipment, etc. The steam turbines will require an overhaul to bring their material condition to the highest level. After these overhauls are performed the regular maintenance schedule will ensure these overhaul items are conducted only when they are required to maintain the turbines. This will result in a levelized budget since overhaul items are spread out over several maintenance cycles. It is recommended that they receive overhauls on the following schedule: Steam Turbine #5 in 2008, Steam Turbine #4 2009, and Steam Turbine #1 in 2010. Steam Turbine #3 was just overhauled in 2005.

It is assumed that, during their life time, each turbine (except STG-1) has been operated on average a similar number of hours each year and are in similar condition.* STG-1 is assumed to be in operation November through April each year.

The maintenance actions recommended below are not intended to be an exhaustive list, but to be used as a guide. These recommendations are based on past operating experience, judgment, and manufacturer's recommendations for similar systems. Table 19 lists the recommended steam turbine maintenance schedule.

Table 19. Recommended steam turbine maintenance.

Maintenance action	Periodicity	Type*	Notes
Borescope steam flow path	Annually	P	Inspect entire steam flow path from turbine stop valve to turbine exit
Lube oil pump capacity test	Annually	F	Ensure Lube Oil pump is pumping to specs
Inspect all control, admission/extraction, and non-return valves	Annually	T	Conduct functional tests, inspect and repair as required
Steam seal system inspection	Annually	T	Inspect and check tolerances repair as required
Governor inspection	Annually	T	Inspect all aspects of governor and test overspeed trip
Generator polarization index	Annually	T	Measure Polarization of generator windings
Generator inspection	Annually	T	Inspection of all mechanicals
Change lube oil filters	Monthly	T	Change lube oil filters
External inspection	Monthly	T	Visual Inspection of the exterior of TG and all auxiliary equipment
* T-Time based (Preventative) maintenance item, P-Predictive maintenance item, F-Failure finding maintenance item			

* An attempt was made to use operating data from the DCS logger software. However, the data was believed to be unreliable.

6.2.2.3 Feedwater

Periodic and condition based maintenance actions will be required to be performed on the feedwater pumps. These items will include vibration analysis to determine bearing health, oil analysis on lubricating oil, replacement of seals and wear rings, periodic disassembly and inspection, turbine overhaul, etc.

The maintenance actions recommended below are not intended to be an exhaustive list, but to be used as a guide. These recommendations are based on past operating experience, judgment, and manufacturer's recommendations for similar systems. Table 20 lists the recommended feedwater system maintenance schedule.

Table 20. Recommended feedwater system maintenance.

Maintenance action	Periodicity	Type*	Notes
Measure wear surfaces	Annually	T	Inspect and check tolerances of OD of the integral impeller wear surfaces and the ID of the casing rings repair as required
Measure OD of inter-stage sleeves	Annually	T	Inspect and check tolerances repair as required
Examine impeller passages for cracks, dents, gauges	Annually	T	Inspect and check tolerances repair as required
Inspect shaft sleeves for excessive wear	Annually	T	Inspect and check tolerances repair as required
De-aerator inspection and NDE	Annually	P	Open and Inspect De-Aerators perform NDE on welds and vessel surface
Feedwater pump turbine annual inspection	Annually	T	Open and inspect turbine steam flow path, check bearings and blade wear, throttle valve internals, carbon ring gland seals, and overspeed trip valve internals
Feedwater pump turbine steam strainer clean and inspect	Annually	T	Clean and inspect the steam strainer
Feedwater pump turbine overspeed trip test	Monthly	F	Test turbine overspeed trip device
Feedwater pump turbine monthly inspection	Monthly	T	Check bearing housings, check oil rings, check and lubricate throttle and overspeed trip linkage
* T-Time based (Preventative) maintenance item, P-Predictive maintenance item, F-Failure finding maintenance item			

6.2.2.4 Condensate

Periodic and condition based maintenance actions will be required to be performed on the condensate pumps. These items will include vibration analysis to determine bearing health, oil analysis on lubricating oil, replacement of seals and wear rings, periodic disassembly and inspection, turbine overhaul, etc.

The maintenance actions recommended below are not intended to be an exhaustive list, but to be used as a guide. These recommendations are based on past operating experience, judgment, and manufacturer's recommendations for similar systems. Table 21 lists the recommended condensate system maintenance schedule.

Table 21. Recommended condensate system maintenance.

Maintenance action	Periodicity	Type*	Notes
Sodium cation polisher resin replacement	Every 5 yrs	T	Sodium cation polisher resin replacement (one unit at a time)
Sodium cation polisher resin treatment	Annually	T	Sodium cation polisher resin treatment (one unit at a time)
Condensate pump turbine Annual inspection	Annually	T	Open and inspect turbine steam flow path, check bearings and blade wear, throttle valve internals, carbon ring gland seals, and overspeed trip valve internals
Condensate pump turbine steam strainer clean and inspect	Annually	T	Clean and inspect the steam strainer
Condensate pump turbine overspeed trip test	Monthly	F	Test turbine overspeed trip device
Condensate pump turbine monthly inspection	Monthly	T	Check bearing housings, check oil rings, check and lubricate throttle and overspeed trip linkage
* T-Time based (Preventative) maintenance item, P-Predictive maintenance item, F-Failure finding maintenance item			

6.2.2.5 Steam

This steam system review is limited to related equipment inside of the CHPP. Maintenance of the district heating system is not considered in this report. Periodic and condition based maintenance actions such as the inspection of carbon steel piping, the cleaning of steam traps, etc. will need to be performed.

The maintenance actions recommended below are not intended to be an exhaustive list, but to be used as a guide. These recommendations are based on past operating experience, judgment, and manufacturer's recommendations for similar systems. Table 22 lists The recommended steam system maintenance schedule.

Table 22. Recommended steam system maintenance

Maintenance action	Periodicity	Type*	Notes
100 psig system bellow expansion joints inspection	Every 5 yrs	T	Inspect expansion joints and replace if required
Pressure reducing stations inspection	Annually	T	Clean and inspect pressure reducing stations
Control, shutoff and check valves inspections	Annually	T	Clean and Inspect valve operation, seats and internals
* T-Time based (Preventative) maintenance item, P-Predictive maintenance item, F-Failure finding maintenance item			

6.2.2.6 *Coal handling*

A major fire occurred in February 2006 in the south coal handling system. This fire caused extensive damage to that system such that it is no longer operational. At this time the cause of the fire is still under investigation and it is outside the scope of this study to speculate as to the reasons that the fire started. However, a comprehensive system of maintenance can likely mitigate the risk of such an event occurring in the future. The cleaning of coal dust accumulations from different points in the system and the testing and maintenance of fire suppression equipment aid in mitigating the risk of fire and / or explosion. The maintenance actions recommended below are not intended to be an exhaustive list, but to be used as a guide. These recommendations are based on past operating experience, judgment, and manufacturer's recommendations for similar systems. Table 23 lists the recommended coal handling system maintenance.

Table 23. Recommended coal handling maintenance.

Maintenance Action	Periodicity	Type*	Notes
Inspect Crusher	Annually	T	Inspect hammer and suspension bars, check tightness and general condition of fasteners, check shafts and pulleys
Inspect Crusher and Conveyor Clutch Assemblies	Annually	T	Inspect Crusher and Conveyor Clutch Assemblies
Inspection of Wear Parts	Annually	T	Grizzlies, apron, belt cleaner and plows, idlers, pulley assemblies, conveyor and feeding belting, storage pile discharger, chutes, magnetic separator, belt scale, duct collectors, exhaust fan
Vibratory Feeder Inspection	Semi-Annually	T	Check all welds and general condition ensure all vibrators are operating clean coal dust build-up
Bucket Elevator Inspection	Semi-Annually	T	Check buckets, belt, bearings, and drives clean coal dust build-up
Conveyor Belts Inspection	Quarterly	T	Inspect all conveyor belts, bearings, rollers clean coal dust build-up
Fire Suppression System Inspection	Quarterly	F	Inspect fire suppression system controls, piping, and equipment to ensure it is functioning properly
Clean Conveyor System	Monthly	T	Clean coal conveyor system and adjust belt scrappers to prevent coal build-up
* T-Time based (Preventative) maintenance item, P-Predictive maintenance item, F-Failure finding maintenance item			

6.2.2.7 Ash handling

The maintenance actions recommended below are not intended to be an exhaustive list, but to be used as a guide. These recommendations are based on past operating experience, judgment, and manufacturer's recommendations for similar systems. Table 24 lists the recommended ash handling maintenance schedule.

Table 24. Recommended ash handling maintenance.

Maintenance action	Periodicity	Type*	Notes
Replace Bags	5 yrs	T	Replace all bags in baghouse
Vacuum System Inspection	Annually	T	Inspect vacuum system integrity especially elbows
Screw Conveyor Inspection	Annually	T	Inspect screw conveyor mechanicals for operation and check liner thickness
Valve Liner Inspection/ Replacement	Annually	T	Valve Liner Inspection/ Replacement

Maintenance action	Periodicity	Type*	Notes
Change Air Compressor Oil	Quarterly	T	Change the oil in the bag house air compressors and send for analysis
Bottom Ash Unloader Inspections	Monthly	T	Inspect the bottom ash gates, associated hydraulic lines and transport piping
* T-Time based (Preventative) maintenance item, P-Predictive maintenance item, F-Failure finding maintenance item			

6.2.2.8 Cooling

The immediacy of the replacement of the current water cooled surface condensers indicate that only minimal reactive maintenance should be performed to keep the units operating until all steam turbines are tied into the air cooled condenser.

The maintenance actions recommended below are not intended to be an exhaustive list, but to be used as a guide. These recommendations are based on past operating experience, judgment, and manufacturer's recommendations for similar systems. Table 25 lists the recommended cooling system maintenance schedule (GEA Power Cooling Systems September 1996).

Table 25. Recommended ACC system maintenance.

Maintenance action	Periodicity	Type*	Notes
Condenser Inspection	Annually	T	Check fan blade pitch, clean blades, clean weep holes, clean motor,
Air Ejector Inspection	Annually	T	Inspect nozzles, inspect inter/after condenser for fouling
Fin Cleaning	Annually	T	High pressure water cleaning of fin tube bundles
Fastener Inspection	Semi-Annually	T	Inspect all hold down fasteners, check for corrosion and retorque
Air Ejector Steam Strainer Clean and Inspect	Semi-Annually	T	Air Ejector Steam Strainer Clean and Inspect
Vibration Switch Test	Semi-Annually	F	Test vibration switches for proper function tighten all hardware
Vacuum Decay Test	Monthly	F	Perform vacuum decay test to ensure proper function of air ejectors
* T-Time based (Preventative) maintenance item, P-Predictive maintenance item, F-Failure finding maintenance item			

6.2.2.9 Water treatment

The maintenance actions recommended below are not intended to be an exhaustive list, but to be used as a guide. These recommendations are based on past operating experience, judgment, and manufacturer's recommendations for similar systems. Table 26 lists the recommended water treatment maintenance schedule.

Table 26. Recommended water treatment maintenance schedule.

Maintenance Action	Frequency	Type*	Notes
RO Membrane CIP Procedure	Annually	T	Clean RO membranes in accordance with the Clean In Place (CIP) procedure
Plate and Frame Heat Exchanger Cleaning	Annually	T	Disassemble, clean, and inspect heat exchanger plates, gaskets and passages
Pre-filtration Skid Media Replacement (sand-anthracite)	Every 5 yrs	T	Replace filter media in the Pre-filter
RO Skid Membrane Replacement	Every 5 yrs	T	Replace RO membranes for all passes
* T-Time based (Preventative) maintenance item, P-Predictive maintenance item, F-Failure finding maintenance item			

6.2.2.10 Electrical

The Power Plant Electrical system includes 12.47 kV, 4160 V, 2400 V, 480 VAC, 120 VAC, and 125 VDC systems and a backup diesel generator for lighting. Tables 27 and 28 lists the recommended maintenance schedule and tests for the transformers, and Table 29 lists the recommended maintenance for the Electrical distribution system.

The maintenance actions recommended below are not intended to be an exhaustive list, but to be used as a guide. These recommendations are based on past operating experience, judgment, and manufacturer's recommendations for similar systems.

Table 27. Transformer inspection/maintenance program.

Maintenance action	Periodicity	Type*	Notes
Inspect for Sagging or Damaged Cables	Annually	T	
Protective Relays	Annually	F	Calibrate protective relays and measure ratio of CTs

Maintenance action	Periodicity	Type*	Notes
Turns Ratio Test	Annually	P	Measure turns ratio
Ground and Power Factor Test	Annually	P	Conduct ground test, verify resistance to ground is within acceptable range and measure insulation power factor
Oil Sample	Semi-Annually	P	Oil sample for dissolved combustible gasses
Bushing Inspection	Semi-Annually	T	Inspect bushings and lightning arrestors for contamination and cracks
Oil Samples	Quarterly	P	See Table 27
Resistance Testing	Quarterly	T	Measure core ground resistance, winding resistance, and resistance to ground
* T-Time based (Preventative) maintenance item, P-Predictive maintenance item, F-Failure finding maintenance item			

Table 28. Transformer tests list.

Quarterly Oil samples to be tested for: a) Acidity b) Interfacial tension c) Dielectric Strength (D1816) d) Water Content e) Power Factor f) Color

Table 29. Recommended electrical maintenance schedule.

Maintenance Action	Periodicity	Type*	Notes
Internal Inspection	Annually	T	Inspect Internals of all switchgear, check bus bars, insulations, cables, retorque bus connectors
Protective Relays	Annually	F	Calibrate protective relays and measure ratio of CTs
Circuit Breaker Testing	Annually	F	Rack out and inspect main circuit breakers, lubricate operating mechanism, test interlocks and trips
Ground and Power Factor Test	Annually	P	Conduct ground test, verify resistance to ground and between phases is within acceptable range and measure insulation power factor
Circuit Breaker Inspection	Quarterly	T	Inspect contact surfaces, linkages, arc chutes and bus connection equipment
Diesel Engine Oil Change	Quarterly	P	Change oil and send sample for analysis
Cable Inspection	Monthly	T	The plant will be broken down into 12 zones and all external cables will be thermal scanned and physically inspected. This is so that all cables will be inspected once a year

Maintenance Action	Periodicity	Type*	Notes
Motor Controller Inspection	Monthly	T	The Plant will be broke down into six zones and all motor controllers in one zone will be cleaned and inspected per month. This is so all Controllers will be inspected semi-annually
Battery Bank Inspection	Monthly	T	Both battery banks will be cleaned and inspected each month
Emergency Lighting Test	Monthly	F	Conduct test to ensure that diesel auto starts and auto transfers. Verify that the generator fuel tank has adequate fuel.
* T-Time based (Preventative) maintenance item, P-Predictive maintenance item, F-Failure finding maintenance item			

6.2.2.11 Instrumentation and control

Proper calibration of the plant instrumentation is paramount to ensure correct decisions are made by the plant operators. Faulty calibration can lead to excessive loads on equipment and increased repair costs due to operating outside of equipment design specifications. Underutilization of equipment can also occur resulting in the loss of value and unnecessary use of additional equipment and energy. Having personnel properly trained and certified to perform calibrations is imperative to any operation. The expansion of the calibration program from just the EPA required instruments (Continuous Emissions Monitoring System, Continuous Opacity Monitoring System, Steam Flow Orifice, and Coal Scales) to all plant instrumentation including all flow, pressure, temperature, electrical, and metering instruments and associated control loops in the DCS. The use of plant instrumentation by both maintenance and operations to monitor trends needs to be addressed. The operators currently only monitor instantaneous data from the DCS and do not use the DCS' ability to trend that data overtime. Using the trending capability of the DCS would allow operators to take actions to stop plant excursions before they came near operating limits. The operators currently wait for alarms before taking corrective actions. Training in trend analysis would increase plant reliability by expanding the operations staff capability of addressing issues before they become large problems. Maintenance could also benefit from trend analysis from the DCS especially relating to the steam turbine generator bearings. The current vibration monitoring system is linked to the DCS and has the capability of being displayed in a trend to show when bearings are encountering problems.

The DCS is a Westinghouse legacy system that is no longer supported by Westinghouse. Spare parts are expensive, require long lead times, or are unattainable. The CHPP staff would like it to be replaced with an updated system. This would also aid in the effort to create a preventative maintenance program by allowing easier collection of information from the DCS database to be analyzed to determine long-term trends in equipment performance. Tracking performance can indicate if a problem is developing with equipment. If a problem is indicated additional measures can be taken to identify and remedy the problem before it becomes a major performance or capability issue for the plant.

Recording and monitoring are equally important aspects of environmental permit compliance. Compliance with permit recording conditions would benefit if routine trend analyses were implemented. Because trending is not routine, the recording function of the DCS is often neglected. As such, recording of information required by the Title V permit can terminate and go uncorrected for an unfavorable period time, leading to large gaps in the permit-required data record. This has been a major cause of past violations. For this reason and due to the overall unreliability of the DCS and long lead times involved in repair, permit-required data should be fed to a second data logging system as backup until the DCS is replaced or a program is implemented to minimize gaps in the permit-required data record.

6.3 Estimated budget

Appendix D contains the recommended budget detailed by system and new technology (diagnostic equipment/tests). The estimated cost in constant 2006 dollars to operate the new RCM system is presented in Table 30. The apparent escalation shown in the budget is actually the increase in cost of repairs as the equipment ages and more problems are discovered with the equipment that requires repairs. The budget includes a contingency amount for unforeseen catastrophic failures that could occur. This amount is included to ensure the CHPP can mount a rapid response to any catastrophic failure. The contingency is separate so it can be applied to any system. The RCM approach to the maintenance program will not require extensive overhauls performed every few years, but calls for spreading this maintenance out over the years and only performing it when the equipment needs it. This results in the levelized budget numbers seen for the Steam Turbines and the Boilers. It is recommended that the Steam Turbines receive one additional (i.e., one last) major overhaul to bring the maintenance actions up to date. That is, it is recommended that they receive overhauls on the following schedule: Steam Turbine #5 in 2008, Steam Turbine #4 2009, and Steam Turbine #1 in 2010. Steam Turbine #3 was just overhauled in 2005 (Personal communication with Pat Driscoll and Mike Meeks). If possible, this schedule could be accelerated to perform these overhauls while the turbines are in an extended outage for the ACC installation. That schedule is presented in Table 1 (p 12). The cost estimates provided in Table 30 are based on the overhauls being conducted on the 2008 to 2010 schedule.

The 2005 Budget presented in Table 2 (p 26) shows that the maintenance labor costs were approximately $930,000* and the total maintenance related expenses were approximately $1,400,000 (exclusive of reactive maintenance and repair costs, which were unavailable). The estimated budget presented in Table 30 for 2006 shows labor costs as $1,100,000, which includes the additional staffing recommended earlier in this report. Table 30 also shows the total cost of implementing and operating the preventative maintenance system for the first year to be $5,730,000 including labor, equipment, and training.

The lack of budgetary records regarding the maintenance of the equipment at the CHPP has required that the budget estimate be based on judgment and past operating experience on similar equipment. The budget is not intended to build on the M&R budget presented in the previous M&R report, but to be a standalone budget reflecting the cost to operate a RCM system. The budget has line items in the balance of plant section that show the cost of consumables and the budget has been developed with an accuracy of +/- 30 to 35 percent. The scope of the estimated maintenance activities is limited to maintenance of the existing equipment. That is, future upgrades or modifications are not included in the budget. Excluded costs in this category, include, but are not limited to:

- future environment control equipment or increased maintenance to meet future environmental requirements
- future capacity to meet heating or electrical capacity needs.

* Maintenance crew labor of $875,692 and electrician labor cost of $54,731 totals $930,423 for maintenance labor.

Table 30. Estimated maintenance program cost summary ($ 2006).

	Estimated Maintenance Program Cost, (2006 dollars)												
Year	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Boilers 1 through 6	1,500,000	1,500,000	1,500,000	1,500,000	1,500,000	1,320,000	1,360,000	1,400,000	1,430,000	1,470,000	1,520,000	1,560,000	1,600,000
Steam Turbine													
ST 1	200,000	100,000	125,000	129,000	1,133,000	137,000	141,000	145,000	149,000	154,000	158,000	163,000	168,000
ST 3	200,000	100,000	125,000	129,000	133,000	137,000	141,000	145,000	149,000	154,000	158,000	163,000	168,000
ST 4	200,000	100,000	125,000	1,129,000	133,000	137,000	141,000	145,000	149,000	154,000	158,000	163,000	168,000
ST 5	200,000	100,000	1,125,000	129,000	133,000	137,000	141,000	145,000	149,000	154,000	158,000	163,000	168,000
Subtotal Steam Turbine	800,000	400,000	1,500,000	1,515,000	1,530,000	546,000	563,000	580,000	597,000	615,000	633,000	652,000	672,000
Balance of Plant													
Coal Handling System	173,000	173,000	173,000	173,000	173,000	176,000	176,000	176,000	176,000	176,000	172,000	172,000	172,000
Ash System (including Baghouse/ID Fan/Env Cont)	161,000	161,000	161,000	161,000	161,000	118,000	118,000	118,000	118,000	118,000	108,000	108,000	108,000
Steam Piping System	107,000	107,000	107,000	107,000	107,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000
Feedwater / Condensate System	63,000	63,000	63,000	63,000	63,000	73,000	73,000	73,000	73,000	73,000	73,000	73,000	73,000
Cooling System	187,000	187,000	187,000	187,000	187,000	44,000	44,000	44,000	44,000	44,000	30,000	30,000	30,000
Water Treatment System	98,000	98,000	98,000	98,000	98,000	34,000	34,000	34,000	34,000	34,000	32,000	32,000	32,000
Instrumentation / Control Systems	99,000	100,000	101,000	101,000	102,000	32,000	33,000	34,000	35,000	37,000	108,000	110,000	111,000
Electrical Distribution System	115,000	117,000	118,000	120,000	121,000	53,000	55,000	56,000	58,000	60,000	92,000	94,000	96,000
Maintenance Shop Equipment, Small Tools, etc.	15,000	15,000	16,000	16,000	17,000	17,000	18,000	18,000	19,000	20,000	20,000	21,000	21,000
Maintenance Consumables	40,000	41,000	42,000	44,000	45,000	46,000	48,000	49,000	51,000	52,000	54,000	55,000	57,000
Subtotal Balance of Plant	1,060,000	1,060,000	1,070,000	1,070,000	1,070,000	640,000	650,000	650,000	660,000	660,000	740,000	740,000	750,000
New Technology													
Computerized Maintenance Management System	100,000	20,000	20,000	20,000	20,000	20,000	20,000	20,000	20,000	20,000	20,000	20,000	20,000
Vibration Analysis Systems	24,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	24,000	2,000	2,000
Thermal Imaging	20,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	20,000	2,000	2,000
Ultrasonic	12,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	12,000	2,000	2,000
Oil Analysis	11,000	11,000	11,000	11,000	11,000	11,000	11,000	11,000	11,000	11,000	11,000	11,000	11,000
Subtotal New Technology	167,000	37,000	37,000	37,000	37,000	37,000	37,000	37,000	37,000	37,000	87,000	37,000	37,000
Subtotal CHPP Bare Erected Costs	3,530,000	3,000,000	4,100,000	4,120,000	4,140,000	2,550,000	2,610,000	2,670,000	2,730,000	2,790,000	2,970,000	2,990,000	3,060,000
Owner's Costs (Engineering @ 5%)	176,000	150,000	205,000	206,000	207,000	127,000	130,000	133,000	136,000	139,000	149,000	150,000	153,000
Subtotal Bare Erected Costs and Owner's Costs	3,700,000	3,150,000	4,310,000	4,330,000	4,350,000	2,680,000	2,740,000	2,800,000	2,860,000	2,930,000	3,120,000	3,140,000	3,210,000
Project Contingency	930,000	790,000	1,080,000	1,080,000	1,090,000	800,000	820,000	840,000	860,000	880,000	1,090,000	1,100,000	1,120,000
Total Plant Maintenance Cost (excluding Staffing)	4,630,000	3,940,000	5,390,000	5,410,000	5,440,000	3,480,000	3,560,000	3,640,000	3,720,000	3,810,000	4,220,000	4,240,000	4,340,000
Total Plant Labor Cost (Recommended Staffing)	1,100,000	1,100,000	1,100,000	1,100,000	1,100,000	1,100,000	1,100,000	1,100,000	1,100,000	1,100,000	1,100,000	1,100,000	1,100,000
Total Plant Cost	5,730,000	5,040,000	6,480,000	6,510,000	6,540,000	4,580,000	4,660,000	4,740,000	4,820,000	4,910,000	5,320,000	5,340,000	5,440,000

Table 30. Estimated maintenance program cost summary ($ 2006) (cont'd).

Year	Estimated Maintenance Program Cost, (2006 dollars)												
	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Total
Boilers 1 through 6	1,650,000	1,690,000	1,640,000	1,680,000	1,740,000	1,790,000	1,840,000	1,900,000	1,950,000	2,010,000	2,070,000	2,130,000	41,250,000
Steam Turbine													
ST 1	173,000	178,000	184,000	189,000	195,000	201,000	207,000	213,000	219,000	226,000	233,000	240,000	5,357,000
ST 3	173,000	178,000	184,000	189,000	195,000	201,000	207,000	213,000	219,000	226,000	233,000	240,000	4,357,000
ST 4	173,000	178,000	184,000	189,000	195,000	201,000	207,000	213,000	219,000	226,000	233,000	240,000	5,357,000
ST 5	173,000	178,000	184,000	189,000	195,000	201,000	207,000	213,000	219,000	226,000	233,000	240,000	5,357,000
Subtotal Steam Turbine	692,000	713,000	734,000	756,000	779,000	802,000	826,000	851,000	877,000	903,000	930,000	958,000	20,426,000
Balance of Plant													
Coal Handling System	172,000	172,000	176,000	176,000	176,000	176,000	176,000	176,000	176,000	176,000	176,000	176,000	4,361,000
Ash System (including Baghouse/ID Fan/Env Cont)	108,000	108,000	108,000	108,000	108,000	108,000	108,000	108,000	108,000	108,000	108,000	108,000	3,021,000
Steam Piping System	50,000	50,000	46,000	46,000	46,000	46,000	46,000	48,000	48,000	48,000	48,000	48,000	1,502,000
Feedwater / Condensate System	73,000	73,000	49,000	49,000	49,000	49,000	49,000	77,000	77,000	77,000	77,000	77,000	1,669,000
Cooling System	30,000	30,000	44,000	44,000	44,000	44,000	44,000	66,000	66,000	66,000	66,000	66,000	1,857,000
Water Treatment System	32,000	32,000	21,000	21,000	21,000	21,000	21,000	44,000	44,000	44,000	44,000	44,000	1,146,000
Instrumentation / Control Systems	112,000	113,000	44,000	45,000	46,000	48,000	49,000	121,000	123,000	125,000	126,000	128,000	2,084,000
Electrical Distribution System	98,000	100,000	71,000	73,000	75,000	78,000	80,000	82,000	85,000	87,000	90,000	92,000	2,167,000
Maintenance Shop Equipment, Small Tools, etc.	22,000	23,000	23,000	24,000	25,000	26,000	26,000	27,000	28,000	29,000	30,000	30,000	547,000
Maintenance Consumables	59,000	61,000	62,000	64,000	66,000	68,000	70,000	72,000	74,000	77,000	79,000	81,000	1,458,000
Subtotal Balance of Plant	760,000	760,000	650,000	650,000	660,000	660,000	670,000	820,000	830,000	840,000	840,000	850,000	19,810,000
New Technology													
Computerized Maintenance Management System	20,000	20,000	20,000	20,000	20,000	20,000	20,000	20,000	20,000	20,000	20,000	20,000	580,000
Vibration Analysis Systems	2,000	2,000	2,000	2,000	2,000	2,000	2,000	24,000	2,000	2,000	2,000	2,000	116,000
Thermal Imaging	2,000	2,000	2,000	2,000	2,000	2,000	2,000	20,000	2,000	2,000	2,000	2,000	103,000
Ultrasonic	2,000	2,000	2,000	2,000	2,000	2,000	2,000	12,000	2,000	2,000	2,000	2,000	80,000
Oil Analysis	11,000	11,000	11,000	11,000	11,000	11,000	11,000	11,000	11,000	11,000	11,000	11,000	285,000
Subtotal New Technology	37,000	37,000	37,000	37,000	37,000	37,000	37,000	87,000	37,000	37,000	37,000	37,000	1,164,000
Subtotal CHPP Bare Erected Costs	3,130,000	3,200,000	3,050,000	3,130,000	3,210,000	3,290,000	3,380,000	3,660,000	3,700,000	3,790,000	3,880,000	3,980,000	82,650,000
Owner's Costs (Engineering @ 5%)	157,000	160,000	153,000	156,000	160,000	165,000	169,000	183,000	185,000	189,000	194,000	199,000	4,133,000
Subtotal Bare Erected Costs and Owner's Costs	3,290,000	3,360,000	3,210,000	3,290,000	3,370,000	3,460,000	3,540,000	3,840,000	3,880,000	3,980,000	4,080,000	4,180,000	86,790,000
Project Contingency	1,150,000	1,180,000	1,280,000	1,310,000	1,350,000	1,380,000	1,420,000	1,540,000	1,550,000	1,590,000	1,630,000	1,670,000	29,530,000
Total Plant Maintenance Cost (excluding Staffing)	4,440,000	4,540,000	4,490,000	4,600,000	4,720,000	4,840,000	4,960,000	5,380,000	5,430,000	5,570,000	5,710,000	5,850,000	116,320,000
Total Plant Labor Cost (Recommended Staffing)	1,100,000	1,100,000	1,100,000	1,100,000	1,100,000	1,100,000	1,100,000	1,100,000	1,100,000	1,100,000	1,100,000	1,100,000	27,470,000
Total Plant Cost	5,540,000	5,640,000	5,590,000	5,700,000	5,820,000	5,940,000	6,060,000	6,470,000	6,530,000	6,670,000	6,810,000	6,950,000	143,790,000

Notes / Clarifications:

1. Asbestos Abatement: No asbestos abatement costs have been included in this analysis, as it is assumed that past refurbishment projects have previously removed the asbestos containing materials (Alaska District August 1998) documented a total plant asbestos abatement cost of $1.5 million.
2. Lead Abatement: No lead containing paint (LCP) abatement costs have been included in this analysis, as it is assumed that past refurbishment projects have previously removed the LCP.
3. In general, WorleyParsons used two sources of cost estimates to develop the estimated costs. 1. Those developed in-house by WorleyParsons, and 2. Those previously estimated for Ft Wainwright (Alaska District August 1998). The values in this reference were escalated from 1998 dollars to 2006 dollars by a 1.25 escalation factor.
4. Maintenance Labor: Routine maintenance is assumed to be performed by plant personnel. Major overhauls, such as the steam turbine overhauls and boiler overhauls are assumed to be performed by outside contractors.
5. Imported Labor: No costs (e.g., travel, per diem, wage premium) for imported labor have been assumed. It is assumed that the local labor force will be able to satisfy the skilled labor requirements.
6. Overhead and Profit: For the estimates developed by WorleyParsons, the overhead and profit were estimated as 8 and 10% respectively. The corresponding information was not detailed by Reference (Alaska District August 1998)
7. Engineering costs. The Contractor's engineering costs are included. The Owner's engineering costs are included and limited to procurement and construction support and estimated at 5% of bare erected cost.
8. Project Management (PM) Costs: PM costs for the contractors are included. PM costs of the Owner are not included.
9. Contingency. A contingency level of 25 to 40% has been assumed to cover the design & construction contingencies and the uncertainties of predicting maintenance and repair requirements 5 to 20 years into the future. To capture an increasing uncertainty with time, the following time dependent contingency factors were used: [2006-10: 25%; 2011-15: 30%; 2016-20: 35%; 2021-30: 40%.]
10. Rounding. The above values might not necessary sum up to the indicated totals due to rounding.
11. The replacement cost of the 12.47 KV switchgear and associated equipment is not included in this budget estimate, because that scope is captured under the electrical distribution study.
12. The line labeled "Total Plant Labor Cost" represents in-house staffing costs. Labor included in other maintenance cost areas is contracted labor.

7 Conclusions and Recommendations

7.1 Conclusions

This work has:

1. Assessed the state of the maintenance management system at the CHPP at Fort Wainwright, AK
2. Identified areas in the current process requiring improvement
3. Recommended changes to implement these improvements
4. Produced proposed maintenance schedules for the major systems
5. Estimated staffing requirements, materials, and equipment required for the maintenance program
6. Estimated a budget required to execute the recommended program over a period of 25 years.

The following section details the recommendations.

7.2 Recommendations

This study recommends that:

1. The existing maintenance program is too reactive; it should be transitioned to a proactive, Reliability Centered Maintenance (RCM) system. This work recommends that the CHPP adopt a RCM approach as detailed in Section 6.1 (p 52).
2. *Long range planning be addressed at the Plant Management level for large maintenance actions and for outage planning*. Major equipment must be overhauled on a regular basis to maintain plant efficiency and re-liability. Section 6.2 (p 55) describes a general RCM implementation, and Section 6.2.2 (p 58) details a system-specific implementation schedule.
3. *A consistent budget be prepared to identify the costs of planned overhauls, major maintenance, regular maintenance actions, and day-to-day consumables*. Section 6.3 (p 69) details an estimated budget.
4. *Operations and maintenance training and manning be addressed to ensure that the plant has the proper number and properly trained personnel to operate and maintain the plant*. Adding an overall Maintenance Manager/Planner will greatly increase the tracking of mainte-

nance actions and productivity of the maintenance department. The addition of an EI&C Supervisor will help the EI&C department coordinate and plan work better to keep items from falling through the crack and coordinating maintenance schedules. The implementation of a RCM program will include an increase in the workload of the Mechanical Maintenance Technicians as well. The addition of two more experienced Mechanical Maintenance Technicians will provide enough additional manpower to cover this workload. The last manning item involves filling the two open EI&C positions with experienced technicians. Table 5 (p 33) lists the recommended manning additions.

5. *The CHPP undertake a formal training and qualification program including Standard Operating Procedures (SOP) and Emergency Operating Procedures (EOP) that would set a standard and provide a means of consistently training new operators and technicians*. The cross training of maintenance personnel as operators would add the benefit of maintenance personnel better understanding the impact of faulty equipment on operations. Original Equipment Manufacturer (OEM) training needs to be done to ensure maintenance personnel can perform all job functions at the desired level of technical competency. OEM training allows the technician to understand how the equipment operates and how it is put together before the item breaks. The time for a technician to learn how an item works and its required maintenance procedures is not after the item has failed. OEM training can also impart helpful troubleshooting tips to speed the troubleshooting and repair process.
6. *All manuals be maintained onsite*. Interviews with the technicians revealed that new technical manuals are kept by the Army Corps of Engineer's office at Fort Wainwright only until the equipment warranty period is over, or if the CHPP personnel have a defined need for them. This slows down the troubleshooting and repair process and prevents technicians and operators from studying the manuals. The plant needs to establish an organized technical library and keep all pertinent drawings on site. All operators and technicians need to be trained in the use and importance of the plant Piping and Instrumentation Diagrams (P&IDs).

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Appendix A: Sample E&IC and Mechanical Log Entries

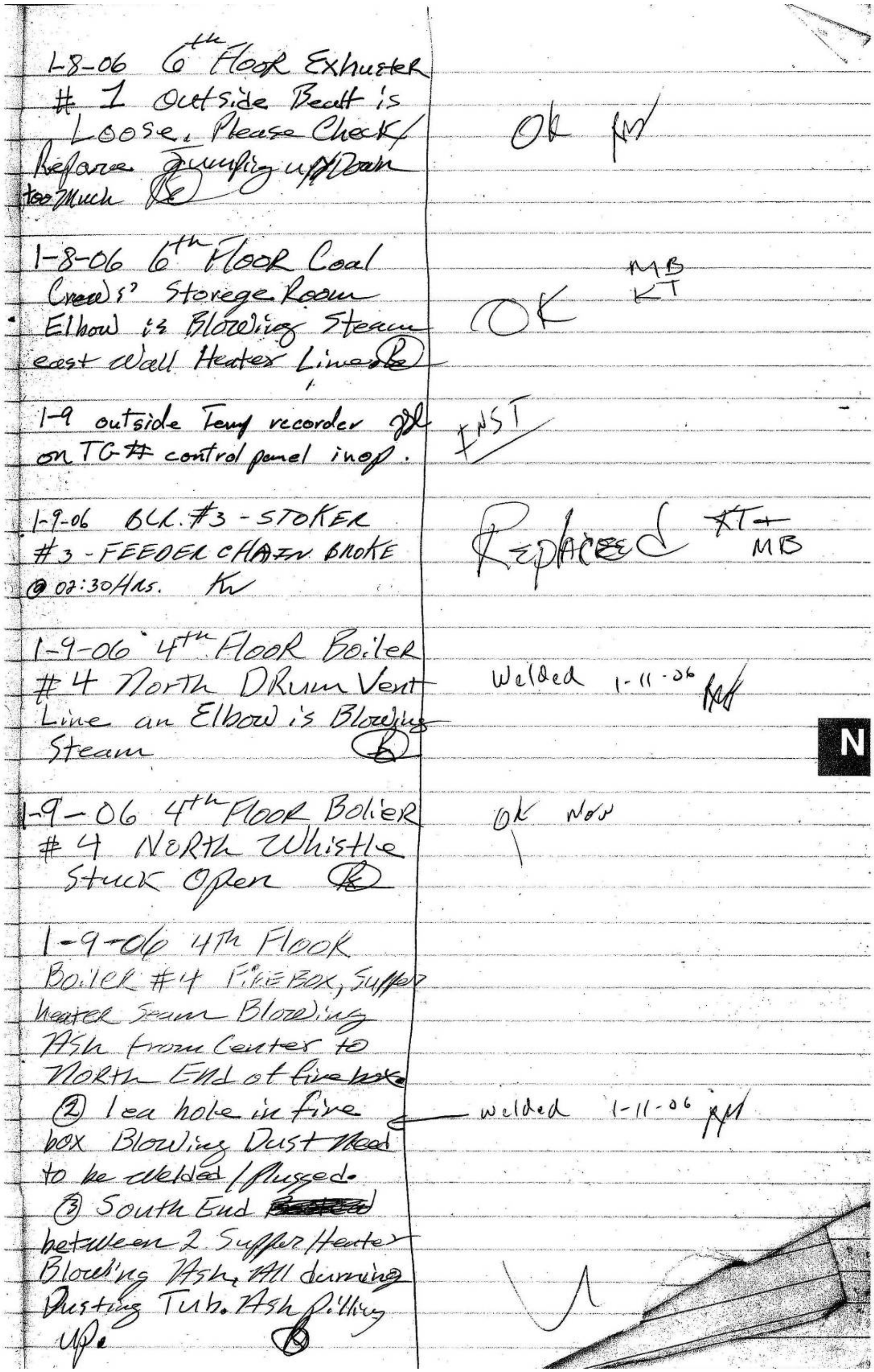
UTILITIES PLANTS SECTION
BUILDING 3595 FT. WAINWRIGHT
Public Works - Alaska 99703

UNIT ________ NUMBER ______ Date Unit Required to be back in service. Date __________
Date Given to Maintenance Supervisor ____________

DEFICIENCIES	Date/Operator	Date repaired	What was done?/By Whom
Neither ash system will run.	P.K. 2/15/6	?	
Baghouse Hopper 5-5	2/16	?	
Allway High could			
be Bad Signal or Not			
empting out compettly	Greg		
04:00 Hrs. - #8 blr - CO/O2		1-18	Blew air back through sample
MONITOR QUIT WORKING?	2-17-06 KW	op	line. OK
			R+R sample pump on #5
			OK
O2 MONITOR - #8 BLK NOT			
WORKING!	2-17-06 KW		
The ram that is wrote-up on	2-19		
2-17, by me on the bottom	KC		
ash bag house is still not			
working. IT WORKS SOMETIMES			
When the regulator is			
tapped on. But IT does			
not work with the other,			
Please Fix? Thanks,			

Checked By Maintenance Work Leader KC Name__________________ Date__________

Figure A1. Example E&IC log.



1-8-06 6th Floor Exhuster
#1 Outside Belt is
Loose. Please Check/
Replace Jumping up/Down
too Much (B)

OK

1-8-06 6th Floor Coal
Crusher's Storage Room
Elbow is Blowing Steam
east wall Heater Line (B)

OK MB KT

1-9 outside Temp recorder
on TG # control panel inop.

INST

1-9-06 BLR. #3 - STOKER
#3 - FEEDER CHAIN BROKE
@ 02:30 HRS. Kw

Replaced KT MB

1-9-06 4th Floor Boiler
#4 North Drum Vent
Line an Elbow is Blowing
Steam (B)

Welded 1-11-06

1-9-06 4th Floor Boiler
#4 North Whistle
Stuck Open (B)

OK Now

1-9-06 4th Floor
Boiler #4 Firebox, Supper
heater Seam Blowing
Ash from Center to
North End of firebox.
(2) lea hole in fire
box Blowing Dust Need
to be welded/plugged.
(3) South End ~~[illegible]~~
between 2 Supper Heater
Blowing Ash, All during
Dusting Tub. Ash Pilling
Up. (B)

welded 1-11-06

Figure A2. Example mechanical log.

Appendix B: Sample CHPP Monthly Inspection and Lubrication Checklist

CHPP MONTHLY INSPECTION AND LUBRICATION CHECKLIST

DATE: _________ NAME: __________________________

Equipment	Lubrication				Remarks
	Grease	Oil Change	Filter Change	Oil Level Check	
Air Compressor #1					SSR Ultra coolant monthly + filters
#2					"
Change air dryer water filters					
Check air dryer seperators					
Ozzie Juice parts washer					Check level, change filter
Ash unloader air filter					Check, clean or replace as needed
Roof Fan Over Turbine Floor N					EP-2 check belts
S					"
ACW Cooling Tower					" check belts
Fresh Air Fan 5th Deck					EP-2
Roof Fan 7th Deck N					EP-2 check belts
S					"
Cross Over to Ash Receiver Room Fan					"
Roof Fan #3					"
#4					"
#5					"
#6					"
#7					"
#8					"
Check ash flappers					replace as needed, grease pivot pins w/ EP2
Mechanical Exhausters #1					Tegra 220 every 2 mos. Due 3-06
#2					"
Crusher Vent Fans W					Lubriplate MAG-1
" E					"
Traveling Pond screen					EP2
Flash Tank Pump					check oil level
Klinker Grinder HPU					"
Condensate Pumps #1					EP2
#2					"
#3					"
#4					
Condensate pump steam turbine					change oil GST 68 6mos due 7-06
Condensate pump steam turbine govenor					change oil SAE 10w due 7-06
Bottom ash door air line #3					Check air-water seperators, oilers
#4					
#5					
#6					
#7					
#8					

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Figure B1. CHPP monthly inspection and lubrication checklist.

CHPP MONTHLY INSPECTION AND LUBRICATION CHECKLIST

DATE: __________ NAME: ____________________________

Equipment	Lubrication				Remarks
	Grease	Oil Change	Filter Change	Oil Level Check	
ACW Pumps Water #1					EP2
#2					"
Glycol #3					"
#4					"
Bypass / Spray Pumps #5					EP-2
#6					"
Condensate Polisher Pumps #1					"
#2					"
#3					"
Sump pumps by waste tank E					EP2
W					"
Sump pumps by waste tank in floor E					"
W					"
Domestic Water Pump N					"
S					"
Base Condensate Pumps					EP-2
North sump pump					EP2
Feed Water Pumps #1					check oil level
#2					"
#3					"
Plant Condensate Pumps					check for leaks
Air Compressor Fresh Air Fans N					EP2
Turbine Oil Purifier					Check differential guages replace filters as needed
Fresh Air Fan by Turbine #3					"
Turbine Hot Well pumps #3 E					check oil level
#3 W					"
#4 E					"
#4 W					"
#5 E					"
#5 W					"
Fresh Air Fan-Station Service					Mobilux or EP2
Turbine HPU pumps #1					check kidney pump differential guage +30 change
#3					"
#4					"
#5					"

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Figure B1. (cont'd).

CHPP MONTHLY INSPECTION AND LUBRICATION CHECKLIST

DATE: __________ NAME: ____________________________

Equipment	Lubrication				Remarks
	Grease	Oil Change	Filter Change	Oil Level Check	
Boiler Grate Drives #3					AW220, ISO 460 every 6 mor Due 7- 06
#4					Due 11- 05
#5					Due 5- 06
#6					Due 5- 06
#7					Due 10 - 05
#8					Due 2-06
Forced Draft Fans #3					Superlube
#4					"
#5					"
#6					"
#7					"
#8					"
Emissions Baghouse Fresh Air Fans VF 1-1					EP2 every 6mos due 3-06
VF 1-2					"
VF 1-3					"
AHU -1					"
ID Fans bearings and louvers #3					EP2 2 pumps only every 6mos due 10/05
#4					" due 5/06
#5					" due 11/05
#6					" due 5/06
#7					" due 5/06
#8					" due 5/06
Baghouse Air Compressor A					AEON 4000 @ 4,000hrs oil filter 1,000hrs air filter as
B					needed record hrs. to next oil or filter change
Baghouse knife gate oilers Boiler #3					GST 32 fill oilers and empty seperators
& water seperators #4					"
#5					"
#6					"
#7					"
#8					"
Baghouse bin thumper oilers Boiler #3					GST 32 fill oilers and empty seperators
& water seperators #4					"
#5					"
#6					"
#7					"
#8					"

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Figure B1. (cont'd).

CHPP MONTHLY INSPECTION AND LUBRICATION CHECKLIST

DATE: __________ NAME: ____________________________

Equipment	Lubrication				Remarks
	Grease	Oil Change	Filter Change	Oil Level Check	
Stack cover screw and bearings #3					Hydraulic oil, Lubriplate MAG-1
#4					every summer Due 7-06
#5					
#6					
#7					
#8					
Check stoker chains					adjust tension, replace missing bolts
Fan bearings over shower room (2)					Superlube
Check fire extiguishers in Maint. Shop					Monthly
Clean strainers for bottom ash door water					Every 6mos. Due 3-06
jackets					
R.O. Pump					Annually Due 10-06
					Chevron AW100 machine oil
Ash unloader dust room fans					grease bearings monthly EP2
Ash unloader dust room prefilters-					Check monthly, clean or replace as needed
Ash unloader dust room srew conveyor					grease bearings monthly EP2
Air cannon oilers -coal scale deck					Fill as needed GST 32

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Figure B1. (cont'd).

Appendix C: TM 5-650, Chapter 5, "Inspection and Preventative Maintenance"

CHAPTER 5
INSPECTION AND PREVENTIVE MAINTENANCE

SECTION I. INTRODUCTION

5-1. PURPOSE AND SCOPE.

This chapter is presented for the information and guidance of those responsible for maintenance of boiler plant equipment. It establishes a complete preventive maintenance system. The use of DA Form 4177, the Utilities Inspection and Service Record, is described. This system of maintenance assignments and records is sufficiently flexible to be applicable to most boiler plant installations. Although this manual schedules most of the maintenance called for by manufacturers, it is not intended to take the place of manufacturer's instruction sheets. Each plant must maintain for ready reference and use a manufactuerer's instruction file on all installed equipment.

5-2. TYPES OF MAINTENANCE.

a. Forced Maintenance. Forced outages for the repair or replacement of equipment parts that have failed in service can be, and often are, very costly. Through the application of proper operating procedures and careful inspection, it is possible to increase the length of time over which a boiler can be carried on the line before any repairs are required. This, in turn, will prolong the useful life of the equipment and minimize forced maintenance. The principal causes of forced outages and excessive maintenance are:

— Sustained and frequent overloading of fuel burning equipment
— Operating with improper air flow conditions
— Fouling of external heating surfaces
— Inadequate water conditioning
— Improper lubrication

Forced maintenance is outside the scope of this manual. Normally, forced maintenance and major overhauls are not performed by operating personnel, but rather by assigned maintenance personnel or outside contractors.

b. Preventive Maintenance. Preventive maintenance can be defined as the systemic and periodic inspection and servicing required to keep equipment in proper operating condition. It means fixing things before they break, thus keeping equipment in continuous service or ready for service. The life of boiler plant equipment depends largely upon its maintenance, and the cost of operation in a well-maintained plant is consistently lower than in a poorly maintained one. In addition, proper preventive maintenance results in improved working conditions and better worker morale.

5-3. RESPONSIBILITY

The chief operator or plant supervisor has the ultimate responsibility for boiler plant equipment, its proper operation, and the scheduling and performance of preventive maintenance. The chief operator should assign to himself responsibility for all inspection and servicing required for plant safety. He will assign other operating or maintenance personnel the responsibility for maintenance of specific pieces of equipment, as required by the preventive maintenance record card system. Some items listed for daily inspection by an assigned individual also require hourly inspections by the operating personnel. These hourly inspections do not relieve the assigned operator of his responsibility to inspect, service, and record the equipment condition.

5-4. INSPECTION.

Inspection is the first step in a preventive maintenance program. The early detection of a problem can greatly reduce the amount of damage, simplify maintenance, and prolong equipment life. The key to effective inspection is a complete understanding of the equipment's operating characteristics. The operator should know the condition, sound, temperature, pressure, speed, vibration, and performance characteristics of each piece of equipment in the plant, and particularly those for which he is assigned responsibility. Any change in normal characteristics should be immediately reported, investigated, and corrected.

5-5. HOUSEKEEPING.

A neat boiler plant generally indicates a well run plant. The boiler plant should be kept free of all unnecessary material and equipment. Good housekeeping should be encouraged and procedures established to maintain the desired level of cleanliness. Equipment should be kept clean. Sometimes cleaning is all that is required to keep equipment in trouble-free operation. Moisture, dirt, dust, cobwebs, bugs, and oil in the wrong place are all enemies of mechanical and electrical equipment. Stop leaks as soon as they are detected. Unrepaired leaks at best represent waste and at worst may cause extensive damage.

5-6. UTILITIES INSPECTION AND SERVICE RECORDS.

Preventive maintenance programs are effective only if careful, accurate, and complete records are kept. In no other way can the Director of Engineering and Housing ensure that all personnel are carrying out their responsibilities and that equipment is being properly maintained. DA Form 4177, shown in figure 5-1, is the basic card from which the record system is assembled. Two separate cards, a field card and a master card, are made up for each major piece of plant equipment. A complete set of master c ards is kept in a loose-leaf binder in the plant office, which the field card becomes a written assignment of work for the operator. The record is complete within itself and is available for inspection by the Director of Engineering and Housing or Army command inspector. A copy of this manual should be kept in each plant to fa cilitate references to the items listed on the cards.

a. Record Card Entries. Care is required to initially fill in the cards properly. Each entry is discussed below.

(1) **Equipment Number.** The equipment number entry is made up of three parts separated by dashes. The first part is the boiler plant building number. The second part may refer to the paragraph in this chapter which discusses the equipment, or it may be a number assigned by the Director of Engineering and Housing, or an equipment classification code. The third part distinguishes between a number of identical or similar pieces of equipment.

(2) **Description.** Describe equipment briefly but in enough detail so that it can be readily identified.

(3) **Preventive Maintenance To Be Done By.** Show the job title and name of the person responsible for maintenance; this should normally be the person who actually operates the equipment. He is also responsible for reminding the chief operator, superintendent, or other supervisor of any special semiannual or annual inspections required, and for ensuring that the supervisor makes the appropriate entry on the card after the inspection is completed.

(4) **Work To Be Done.** Study this manual and the equipment manufacturers manual, noting all inspection and service required. Enter in this space the paragraph or subparagraph heading describing the operation. Add any operations not covered in the manual but needed to maintain the unit. Ensure that all necessary inspections and services are shown on the record card. List operations in order of frequency of performance, with daily service first.

(5) **Item Number.** Identify each operation with the proper item number. Usually the item number is the subparagraph number unless an item number is noted. Where the same item number is used to identify more than one operation, differentiate between them by adding a letter to one of the numbers; thus, if "1" is used twice, write one of them as "1a".

(6) **Reference.** Insert paragraph numbers to facilitate reference to the appropriate manual.

(7) **Frequency.** Record frequency of operations, as shown in Time-Schedule columns. Modify suggested frequencies as required to fit local conditions.

(8) **Time.** Show specific day or month when service is due. Stagger quarterly semiannual, and annual inspections so as to minimize rush periods and schedule conflicts. Choose the season when the work can be best accomplished.

(9) **Tab Index.** Mark an X at the top of the form alongside each month during which work is to be done or a report submitted. This helps to schedule operations, since overall work required in a given month can be quickly determined by reference to the tab index.

(10) **Service Record.** On the back of the card, record the date and item number whenever maintenance is performed, and initial. If service is required beyond the ability or authority of the inspector, he must request the proper help and enter the request in the Work Done column. For example, if inspection of a motor reveals a grooved commutator, the entry would read Electrician needed t complete Item 51 — commutator grooved. The work order number is entered under the column headed Signed and is initialed. When all spaces on the Service Record are filled in, a blank card should be stapled to the original.

b. Assignment of Work. Only general rules covering assignment of preventive maintenance work are given here. Actual assignments will necessarily depend upon the specific plant and the qualifications of operating personnel. Work loads of all personnel should be substantially equal, and duties assigned must be in keeping with the qualifications of the individual. A coal handler, for example, may inspect the stack and breeching for fly-ash accumulations, and examine guy wires, coal bunkers, elevators, and conveyors. He should not be expected to maintain and adjust flow meters or combustion controls.

(1) **Chief Operator/Supervisor.** The chief operator is charged with overall responsibility for the plant. Therefore, inspections having to do with safety of operation or the possibility of serious damage to equipment are assigned to him. These items must be checked at frequent intervals. Likewise, items of major importance such as internal inspection of boilers and furnaces should be under his personal supervision.

(2) **Regulag Operators.** Shift operators, firemen, or other qualified personnel usually have maintenance duties in addition to their regular assignments. The man to whom a given piece of equipment is assigned should perform the required maintenance during whatever shift he happens

to be working on a given day. During this man's time off, the relief operator or the chief operator performs the scheduled maintenance. Maintenance activity can sometimes be assigned entirely to day-shift operators. This arrangement necessitates close supervision to guard against neglect, but maintenance work during daylight hours is more pleasant and frequently more effective.

(3) **Maintenance Men.** In plants where regular maintenance men are available, assignment of preventive maintenance work is simplified. Here day-shift work is usual. However, certain special items should still be assigned to skillful operators.

c. **Record Card Example.** Figure 5-1 illustrates a Master Record Card for a typical boiler. In this example the boiler is the No. 2 boiler located in building NN11. A Field Record Card would be similar, but would also include initials for all daily inspection and servicing performed.

d. **Use of the Record Card System.** The Record Card System consists of duplicate sets of the DA Form 4177 card, one set making up a Field File and the other the Master File. The Field File is made up of the forms forwarded to the operator who maintains the equipment. A copy of this manual is maintained in the plant to explain duties. The assigned operator makes all service entries and keeps his copies of the forms up to date. Forms in the Field File are kept in the operator's possession except at the beginning of the month, when they are sent to the supervisor for transfer of consolidated data to the Master File. Record cards in the Master File are arranged by equipment number and kept in the work supervisor's office. A movable tab is placed on the tab index of each card, above the month during which maintenance for the unit is next scheduled. When operators turn in the Field File at the beginning of the month, entries are checked to ensure that all work was done and a summary of the entries is transferred to the Master File. The summary includes any special difficulties encountered by the operator, work orders required for maintenance, and the consolidated entry of items checked. After all entries are made, movaable tabs are then shifted to the next month when maintenance is scheduled and Field File cards are returned to the operator. Any tabs in the Master File that are not moved are readily apparent. Since they indicate that a Field File card was not turned in or that work was not completed, immediate follow-up is essential. Careful supervision and attention to detail in setting up the system will pay dividends in accomplished maintenance and more efficient operation.

5-7. TOOLS.

Proper preventive maintenance requires proper tools and instruments. Review the operations listed on the maintenance cards and determine the tools required for each operation. There is no single list of tools which will apply to all plants. However, each plant should be equipped with a workbench with a pipe vise, a machinists vise, and a tool board.

a. **Special Tools.** Some maintenance operations require tools which would be used too infrequently to justify their purchase for the central boiler plant. If possible, such tools should be borrowed from other departments on the post; otherwise, requisition them. Indicate on the maintenance card the department from which they may be borrowed.

b. **Care of Tools.** Maintain all tolls in first-class condition. Take defective tools out of service immediately and repair or replace them. Use tools properly. If the proper tool for an operation is not available, immediate arrangements should be made for its procurement.

c. **Tool Board.** Keep all tools on a well-planned tool board or tool box, not in binx, benches, or drawers. Keeping tools on a tool board helps prevent loss and makes them instantly available when required. Locate the tool board in a conspicuous place, convenient to the majority of operators. Space should be provided on the board for additions to the tool supply. A board made of wood is especially sattisfactory since it is easily constructed and special hangers and brackekts required for the tools can easily be fastened to it. Steel tool boards are mor durable and are also frequently used. The shape or size of a tool should not prevent its being installed on the tool board. Extension cords, oil cans, flashlights, and electric drills can be installed on the board by use of special brackets. The outline of each tool should be painted on the board in a contrasting color to assist in replacing tools in their proper place and to serve as a ready check on missing tools.

5-8. SPARE PARTS.

Preventive maintenance requires an adequate stock of spare parts. Service conditions, the importance of the part to service continuity, and the ease of procurement all help to determine the kind and number of spare parts kept in stock. Examine the equipment requirements in the plant and prepare a spare parts inventory. Do not neglect to include small parts such as nuts, bolts, shear pins, steam traps, gaskets, valve seats, packing, and cotter pins.

5-9. SPECIAL SUPPLIES.

ubricants and cleaning solvents are needed for proper equipment operation and long life. Clean, properly lubricated equipment is required for successful plant operation.

a. **Lubricants.** Lubricants are frequently referred to in the Scheduled Preventive Maintenance section. Because of the extreme variations in equipment and service

JAN	2	FEB		MAR		APR	SA 2	MAY		JUN		JUL	2	AUG		SEP		OCT	A 2	NOV		DEC	

EQUIPMENT NUMBER NN11-511-2 DESCRIPTION IRON CITY BOILER #2, 350 HP FIRETUBE

PREVENTIVE MAINTENANCE TO BE DONE BY C. JONES, CHIEF OPERATOR

ITEM NR	WORK TO BE DONE	REFERENCE	FREQUENCY	TIME
1	EXTERNAL INSPECTION	5-11a	Daily	
2	TEST BOILER WATER SAMPLES	5-11a	Daily	AM
3	BOTTOM BLOWDOWN	5-11a	Daily	PM
4	CLEAN BOILER EXTERIOR	5-11a	Daily	
5	LEVER TEST SAFETY VALVES	5-11b	Monthly	2nd Monday
6, 7	CHECK BOILER DRAIN VALVES & FLOOR DRAINS	5-11b	Monthly	
8	INTERNAL & EXTERNAL INSPECTION	5-11c	Quarterly	
9	CLEAN FIRESIDE OF BOILER	5-11c	Quarterly	
10	EXTERNAL INSPECTION	5-11d AR420-49	Semi-Annual	APR
11	ANNUAL INSPECTION	5-11e,f AR420-49	Annual	OCT

*SCHEDULE INSPECTION AND SERVICE ON THIS SIDE. **CORD INSPECTION AND SERVICE ON REVERSE SIDE.*

DA FORM 1 OCT 73 4177 REPLACES DA FORM 9-34.

UTILITIES INSPECTION AND SERVICE RECORD

For use of this form, see TM 5-600 series, the proponent agency is Office of the Chief of Engineers.

RECORD OF INSPECTIONS AND SERVICE

DATE	WORK DONE	INITIAL	DATE	WORK DONE	INITIAL
1/11/82	Item 5,6 & 7	CJ	10/11/82	Item 5,6 & 7	CJ
1/13/82	Item 8 & 9	CJ	10/13/82	Item 9 & 11 Annual Inspection	CJ
2/8/82	Item 5,6 & 7	CJ	10/14/82	Brush & Wash Waterside	CJ
2/18/82	Reseat blowdown valve	CJ	10/14/82	Replace fusible plug	CJ
3/8/82	Item 5,6 & 7	CJ	11/8/82	Item 5, 6 & 7	CJ
4/12/82	Item 5,6,7 & 10	CJ	12/13/82	Item 5, 6 & 7	CJ
4/14/82	Item 8 & 9	CJ			
4/27/82	Repack mainsteam valve	CJ			
5/10/82	Item 5,6 & 7	CJ			
6/14/82	Item 5,6 & 7	CJ			
7/12/82	Item 5,6 & 7 J.T. 7/12/82	CJ			
7/15/82	Item 8 & 9 J.T. 7/15/82	CJ		This illustrates a master	
7/19/82	Repair refractory front wall	CJ		recorder card which has consoli-	
7/20/82	Work Order No. 261	SB		dated the daily and other	
8/9/82	Item 5,6 & 7	CJ		entries from the field record	
9/13/82	Item 5,6 & 7	CJ		card.	

FIGURE 5-1. RECORD CARD EXAMPLE

conditions, the types of lubricants required for a given plant must be determined locally. The equipment manufacturers instructions, advice from lubricant manufactuerers, and advice of the Director of Engineering and Housing help to determine the lubricant requirements. Tables 5-1 and 5-2 are provided to list stock numbers and uses for standard Army lubricants.

b. Cleaning Solvents. Cleaning solvents such as mineral spirits, kerosene, and Varsol can be used in central boiler plants. Petroleum derivatives such as naphtha and gasoline present an explosion and fire danger and must never be used. Benzene especially must never be used, as it not only has a low flashpoint, but is also extremely toxic. Follow the precautions for use and storage that are provided with the solvents. When using cleanilng solvents, be sure the solvent is completely evaporated before placing the equipment back into service. When using solvents for cleaning electrical equipment, first remove all loose dirt and dust, then dip a rag into the solvent and wipe the insulation. When spraying solvents, extra precautions against fire or health hazards must be observed. When spraying solvents, extra precautions against fire or health hazards must be observed. When cleaning bearings or machined parts, place the cleaned parts on clean rags or paper, allow them to dry and immediately dip them in oil or apply lubricant. Do not allow rust-susceptible parts to remain exposed to air after cleaning.

SECTION II. SCHEZDULED PREVENTIVE MAINTENANCE

5-10. SCHEDULING AND USE OF THE INFORMATION.

The following sections provide suggested preventive maintenance schedules for many types of central boiler plant equipment. The subparagraph designates the frequency for preventive maintenance: daily, weekly, monthly, quarterly, semiannually, and annually. The second subparagraph numbers are numbered consecutively and can be used as index numbers on the record cards. The lists of inspection and work presented here should not be considered to be complete. Review the manufacturers operating and maintenance instructions and add additional required items. Review the applicable ASME Code and the National Board Inspection Code published by the National Board of Boiler and Pressure Vessel Inspectors, 1055 Crupper Avenue, Columbus, Ohio 43229, for additional requirements and suggestions. Other equipment will be found which is not discussed in this section. Such equipment should be researched with the manufacturer and appropriate record cards prepared. The frequency suggested here is based on good practice. Modify the suggested frequency to best match local conditions and experience.

5-11. BOILERS.

The successful operation and maintenance of a boiler is greatly dependent on the operation and maintenance of its auxiliaries. Boiler operation and boiler preventive maintenance both involve the inspection of the boiler operating conditions.

a. Daily

(1) Check the following conditions and take action as required

(a) Water level.

(b) Steam pressure or water temperature stability.

(c) Flue gas temperature at two loads, compared to clean boiler temperatures.

(d) Flue gas oxygen or carbon dioxide levels at two loads, compared with baseline data.

(e) Water or steam leaks.

(f) Air leaks in casing, ducts, or setting.

(2) Take water samples and perform necessary tests per chapter 4. Adjust internal treatment and continuous blowdown.

(3) Blow down steam boilers through the bottom blowdown connection to remove sludge.

(4) Clean boiler exterior.

b. Monthly.

(1) Item 5. Lever test all safety valves. Reference paragraph 5-15.

(2) Item 6. Check all boiler drain valves for proper opening and closing.

(3) Item 7. Check boiler room floor drains for proper function.

c. Quarterly. One of the quarterly inspections should be timed to coincide with the annual inspection by the Authorized Inspector.

(1) Item 8. Internally and externally inspect the boiler. Reference semi-annual and annual procedues.

(2) Item 9. Clean the fireside of the boiler.

d. Semi-Annually. Semi-annually or as required by AR 420-49 an external inspection of the boiler by an Authorized Inspector is required. Item 10. With the boiler operating, inspect for the following:

(1) Any evidence of steam or water leakage.

(2) Pressure gage accuracy and function.

(3) Safety or safety relief valves.

Table 5-1. Lubricating Oils, Greases, and Preservatives

Product	Military Specification Number	Symbol	Approximate SAE Grade(1)	National Stock Number(2)	Temperature Above
Lubricating oil, general purpose	MIL-L-15016A	2075	20W		-10°F
		2110(3)	10W-75W	9150-00-223-4137	0°F
		2135	20W-75W	9150-00-231-6664	0°F
		2190	30W	9150-00-231-6639	35°F
		2250	40W		35°F
		3050(3)	20W	9150-00-223-4138	0°F
		3065	30W-80W		5°F
		3080	40W-90W	9150-00-223-8890	15°F
		3150	140W	9150-00-240-2258	25°F
Lubricating oil, compounded	MIL-L-15019B	4065	40W	9150-00-243-3196	35°F
		6135	140W	9150-00-231-6645	60°F
		8190	30W	9150-00-231-9033	35°F
Lubicating oil, mineral, cylinder	MIL-L-15018B	5190	140W	9150-00-240-2260	60°F
Lubicating oil, steam turbine (noncorrosive)	MIL-L-17331B	2190TEP	30W	9150-00-235-9061	60°F
Lubricating oil, internal combustion engine, subzero	MIL-L-10295A	OES		9150-00-242-7603	-65° to 0°F
Lubricating oil, instrument jewel-bearing, nonspreading low temperature	MIL-L-3918	OCW		9150-00-2270-0063	-40°F
Lubricants; chain, exposed-gear and wire rope	VV-L-751A	CW-11B		9150-00-246-3276	All
Lubricating oil, internal combustion engine	MIL-L-2104A	OE-10	10W	9150-00-265-9425	20°F
		OE-30	30W	9150-00-265-9433	0°F
		OE-50	50W	9150-00-265-9440	15°F
Grease, automotive and artillery	MIL-G-10924A	GAA		9150-00-190-0907	-65° to 125°F
Grease, ball and roller bearing	MIL-G-18709	BR		9150-00-249-0908	125° to 200°F
Grease, graphite	VV-G-471C	GG-1		9150-00-272-7652	125° max.
Lubricating oil, internal combustion, preservative	MIL-L-21260	PE-1		9150-00-111-02-1 9150-00-111-0208	
Lubricating oil, preservative, medium	PL-MED			9150-00-231-2356	
Corrosive preventive, petroleum,hot application	MIL-G-11796A	CL-3		8030-00-231-2353	
Corrosion preventive, compound, solvent cutback, cold application	MIL-C-16173B	CT-1		8030-00-231-2362	

NOTES

(1) SAE numbers 10W through 50W are for crankcase lubrication. SAE numbers 75W through 140W are for transmission lubrication.

(2) National stock numbers are for 5-gallon containers for lubricating oils and 35-pound containers for grease, except 1/2-ounce can for MIL-L-3918. For other containers, see Federal Supply Catalog.

(3) Quenched.

Table 5-2. Lubricating Oil and Grease Uses

Equipment	Oil or Grease Symbol
Air compressors	
Vertical with splash lubrication	
Gage pressure less than 100 psi	2110, 3050
Gage pressure greater than 100 psi	2135, 2190, 3050
Horizontal	2135, 2190, 3050
External lubrication, sight feed, wick feed, hand oiling	2135, 2190, 3050
External lubrication, circulating systems or splash type crankcase	2110, 2135, 3050
Cylinders: Wet conditions	8190
Dry conditions	2190, 2250, 3065
Bearings:	
Ball, all temperatures to 200°F	BR
Ball, low-pitch line speed	
Operating temperature below 32°F	2075
Operating temperature 32° to 150°F	2190, 2250, 3065
Ball, medium-pitch line speed	
Operating temperature below 32°F	2075
Operating temperature 32° to 150°F	2135, 3050
Ball, high-pitch line speed	
Operating temperature below 32°F	2075
Operating temperature 32° to 150°F	2110, 3050
Ring-oiled, small, miscellaneous	2110
Kingsbury thrust bearing	2190TEP
Thrust (other than Kingsbury, subject to water)	4065
Thrust (other than Kingsbury, not subject to water)	2135, 2190
Bronze guide	GAA
Countershaft	CG 1
Differential (enclosed)	3150, 5190, 6135
Eccentric	3065
Guide	GAA, CG 1

Equipment	Oil or Grease Symbol
Oilite bronze bushings	OE10, OE30
Pillow block	GAA
Underwater-babbitted	GAA, CG 1
Universal joint, slip splines	BR
Chain Drives	
Roller	3080, GAA, CG 1
Roller (enclosed)	Winter, 2075; Summer, 3065
Roller (semienclosed)	Winter, 3080; Summer, 6135
Slow-speed	CW-IIB
Medium-speed	5190
Chemical feeders	See manufacturer's instructions
Clarifier equipment	Do.
Couplings	6135
Drive jaw clutch	OE50
Gear case or gear head	Low temperature, 3080, high temperature, 5190
Gears	
Herringbone	Winter, 2075; Summer, 3065
Helical	Do.
Motor reducers	Winter, 3050; Summer, 2135
Open	5190
Planetary	Winter, 2075, 2110; Summer, 2135
Worm and pump transmission	Winter, 3080; Summer, 6135
Instruments	OCW
Motors	See manufacturer's instructions
Packing, Sludge Pumps	4065, 6135
Pumps	See manufacturer's Instructions
Seal packings	GAA
Shafting	
Large	2190, 3065
Small	2110, 2135, 3050
Shear pins	WB
Sheaves	CG 1, GAA
Solenoid oilers	3050
Valve stems	GAA

(4) Water level gage function.

(5) Pressure controls function.

(6) Low water fuel cutoff and level control function.

(7) Steam, water, and blowdown piping for leakage, vibration, proper rating, and freedom to expand.

(8) Review the boiler log, maintenance records, and water treatment records to ensure that regular and adequate tests have been made.

e. Annually. Annual inspections are required by AR 420-49. Boiler inspections are to be made in accordance with Rules for Inspections in Section VII of the ASME Boiler and Pressure Vessel Code. An Authorized Inspector is required. Preparation for an annual inspection is discussed in the next subparagraph. The most recent copy of Boiler Inspection Report, DA Form 416, must be posted for each boiler in the plant.

(1) Item 11. Inspect the boiler for the following; clean and repair as required:

(a) Water side of tubes for deposits caused by water treatment, scale, or oil. Remove excessive deposits by mechanical or chemical means.

(b) Stays and stay bolts. Repair or replace as required.

(c) Water side of tubes and boiler for corrosion, grooving, and cracks.

(d) All manholes, internals, and connections to the boiler for cracks, corrosion, erosion and clean passages.

(e) Fusible plugs. Replace annually.

(f) Tube sheets, tube ends and drums for signs of thinning, leaking, corrosion, or cracks.

(g) Boiler supports and setting for freedom of expansion.

(h) Fire side of tubes for bulging, blistering, leaks, corrosion or erosion.

(i) Setting for cracks, settlemlent, loose bricks, spallilng, and leakage.

(j) Safety valves and their connections and piping. Test the safety valves.

(k) Baffles.

(l) Blowdown piping.

(m) Boiler appliances.

(n) When required by the Authorized Inspector, hydrostatically test the boiler.

(o) Review past inspection reports and plant records.

(p) Make any other inspection required by the ASME Code or National Board Inspection Code.

(2) **Preparation for an Annual Inspection.** Make the following preparations for annual inspection. Other preparations may also be required by the ASME or National Board Inspection Codes.

(a) Where sootblowers are installed, blow soot before reducing boiler load below 50 percent.

(b) Shut down the boiler per paragraph 3-33. Shut off fuel supply lines and lock when possible. Sufficiently cool the boiler before draining the water. Internally wash the boiler to remove sludge deposits, suspended solids sediment, and loose scale. Do not clean drums or tubes until after the inspection unless prior agreement has been reached with the Authorized Inspector.

(c) Before opening or entering any part of the boiler, ensure that the nonreturn and stop valves are closed, tagged, and preferably padlocked and drain valves between the two are opened. The feed and check valves must be closed, tagged, and padlocked and drain valves between the two must be opened. After draining the boiler blowoff valves must be closed and padlocked. All drain and vent lines should be opened.

(d) Proper low voltage lighting should be provided for internal inspection.

(e) The fire side walls, baffles, and tubes should be thoroughly swept and ash and soot removed.

(f) If the installation burns coal, remove the grate bars, and clean the firebox plates along the grate line until the bare metal is exposed. Take care not to damage the metal during the cleaning.

(g) Have available a supply of gaskets for manholes and handholes, and suitable wrenches for removing and replacing covers.

(h) Replace fusible plugs.

(i) If insulation conceals manufactuerers inscribed data, remove the lagging and clean the surface carefully so that die-cut letters and figures can be easily read.

(j) Assign a qualified boiler plant operator to assist the Inspector throughout the tests.

(k) Be prepared to run a hydrostatic pressure test. A hand pump should be provided for this test if required. Provide gags to prevent safety valves from lifting when test pressure is applied. If hydrostatic pressure tests on more than one boiler are contemplated, sufficient gags should be provided for all the boilers. If boiler gages and controls are not designed for the proposed test pressure, be prepared to isolate or remove them and plug the openings.

(1) Have boiler records available.

f. Taking a Boiler Out of Service. Whenever a boiler is to be out of service for more than two days, thoroughly clean the fire side of the boiler, flues, economizer and air heater. Ash and soot deposits must be removed. Dry ash and soot are not corrosive but moisture in combination with the ash and soot of sulfur bearing fuel is. To avoid acid attack and corrosion of the metal, ash and soot must be removed.

5-12. ECONOMIZERS.

Reference paragraph 2-7.

a. Daily: Inspect for leaks in piping, valves, packings, gasketed joints, handhole openings, casing, etc. Make repairs as required.

b. Monthly. Check the following under identical load conditions:

(1) Item 2. Water pressure drop through the economizer.

(2) Item 3. Draft losses across the economizer.

(3) Item 4. Gas temperature drop across the economizer. An increase in draft loss and a decrease in gas temperature drop normally indicates a fouling condition.

c. Annually. During the annual boiler overhaul, clean and inspect the economizer. AR 420-49 and ASME Boiler and Pressure Vessel Code requires inspection of the economizer in addition to the boiler.

(1) Item 5. Externally look for signs of overheating, leakage, wear, or corrosion in pressure parts. Check the baffles and tubes in the area of sootblowers for signs of abrasion caused by fly ash or steam cutting. Check the elements of the sootblower.

(2) Item 6. Internally look for corrosion, erosion, scale, sludge deposits, or oil in tubes and headers.

5-13. AIR HEATERS.

Reference paragraph 2-8.

a. Daily.

(1) Inspect the air heater for gas or air leaks in duct, casing, gasketed joints, etc.

(2) Inspect for abnormal air or gas temperatures.

(3) Inspect for mechanical drive problems on rotary air heaters, if supplied.

(4) Establish a lubrication schedule for rotary air heaters in accordance with the manufacturers recommendations.

b. Monthly: Item 5. Check the following under idential load conditions:

(1) Air and gas side draft losses.

(2) Gas temperature drop through the air heater.

(3) Inspect for mechanical drive problems on rotary air heaters, if supplied.

(4) Establish a lubrication schedule for rotary air heaters in accordance with the manufacturers recommendations.

b. Monthly: Item 5. Check the following under identical load conditions:

(1) Air and gas side draft losses.

(2) Gas temperature drop through the air heater.

(3) Air temperature rise through the air heater. An increase in gas side draft losses combined with a decrease in air temperature rise indicates excessive soot deposits in the tubes or gas passages.

(4) Make an orsat or oxygen analysis of the flue gas at the air heater inlet and outlet. The difference in total air content between the analyses indicates air leakage. Repair if leakage is excessive.

c. Annually.

(1) Item 6. During the boiler overhaul, clean and inspect the air heater. Look for indications of corrosion, erosion, leakage, and wear.

(2) Item 7. In rotary regenerative air heaters, inspect the motor drive, speed reducer, auxiliary air motor if provided, lubricating system, cooling system, bearings, rotor seals, etc.

(3) Item 8. Check the condition of sootblowers and washing equipment.

5-14. WATER COLUMNS.

Reference paragraph 2-11.

a. Daily.

(1) Blow down and inspect all water columns, gage glasses, level indicators, and level alarm devices for leaks, correct operation, correct level indication, and adequate lighting. Repair leaks immediately.

(2) Check to see that valves between boiler and gage glass are free and operational.

(3) When provided, test high and low automatic alarm to ensure that it is in perfect order. Repair when faulty.

b. Annually: Item 4. During annual boiler overhaul, or more often if necessary, dismantle, clean, and inspect all parts such as valves, alarm linkages, floats, chains, alarms, glasses, diaphragms, or electrodes. Replace or repair damaged or worn parts are required to ensure proper functioning.

5-15. SAFETY VALVES.

Reference paragraph 2-13.

a. Daily.

(1) Check for steam leakage indicating damaged seat, defective parts or lodged scale. Correct immediately such faults as leaking, simmering or chattering.

(2) Check supports and anchors of discharge pipe.

(3) Check the drain line from safety valve outlet to ensure that it is open and will function when needed.

b. Monthly: Item 4. Check each safety valve by raising the valve off the seat by listing the lever. Keep the valve wide open for at least 10 seconds to blow dirt and scale clean from the seat. Close the valve by suddenly releasing the lever.

c. Annually: Item 5. Before and after the annual steam generator inspection and overhaul, test the operation of all safety valves. Testing is also required whenever the spring or blow back ring has been reset or adjusted.

5-16. FUSIBLE PLUGS.

Reference paragraph 2-16. These items should be put on the boiler record card where applicable.

a. Quarterly: Inspect fusible plugs during boiler inspections. Scrape the surface clean and bright. Replace if the metal does not appear sound.

b. Annually: Item 2. Replace fusible plugs at least once a year.

5-17. SOOTBLOWERS.

Reference paragraph 2-17b.

a. Daily.

(1) Check for leaks. Repair if required.

(2) Check for correct operation of the system components.

b. Semi-Annually.

(1) Item 3. During the boiler outages, inspect the following items and repair if required:

(a) Defective elements (warped, corroded, eroded, or otherwise damaged).

(b) Worn, loose, or defective nozzles. (c) Incorrect blowing and adjustment.

(d) Incorrect location of elements or nozzles.

(e) Alignment and tightness of the supporting bearings.

(f) Defective chains, control valves, and control system components.

(g) Condition of sootblower piping system.

(h) Evidence of abrasion caused by impingement of the jet.

(2) Item 4. Repack and adjust glands to prevent leakage.

5-18. STOKERS.

Reference paragraph 2-18.

a. Daily.

(1) Clean exposed parts of the stoker.

(2) Inspect all accessible parts. Pay special attention to bolts and connections in shear pins or safety release mechanisms. Be sure there is no binding which may keep the protective devices from functioning. Operating personnel should inspect the following items hourly:

(a) Hot bearings.

(b) Foreign material in coal.

(c) Mechanical linkages.

(d) Damaged, overheated, or burned out parts.

(e) Oil leaks.

(f) Proper oil level and condition of hydraulic systems.

(g) Correct oil pressures and oil temperature.

(h) Clinkers.

(3) Establish lubrication requirements and a schedule in accordance with the manufacturers requirements.

b. Quarterly. Make the following general inspection and overhaul whenever a boiler is removed from service.

(1) Item 4. Inspect the complete stoker. Check for wear on surfaces of feeder-box sides, conveyor areas, and all moving parts. Check alignment and condition of the grates. Replace broken, warped, or distorted parts promptly. Check the following:

(a) Clearances between grate elements.

(b) Tightness of all nuts, bolts, and holding parts.

(c) Drive mechanism and drive unit. Clean and repair any damage to gears and other components.

(d) Bearings of drive unit. Lubricate as required.

(e) Electrical controls and connections.

(f) Fan and its bearings. Check and lubricate bearings.

(g) Fly-ash reinjection system. Look for worn areas and plugged lines. Repair if required.

(h) Air seals. Repair if required.

(2) Item 5. Remove slag from furnace walls adjacent to stoker or fuel-bed surface. Take care to avoid injury to the brickwork.

5-19. PULVERIZED COAL EQUIPMENT.

Preventive maintenance procedures for pulverized coal equipment may be found in manufacturers instructions and Navy Manual MO-205.

5-20. COAL HANDLING EQUIPMENT.

Reference paragraph 2-19.

a. Daily.

(1) Inspect for the following hourly:

(a) Unusual noise or vibration.

(b) Motor overheating.

(c) Hot bearings.

(d) Coal accumulation. Clean as required.

(e) Correct chain or belt tension.

(f) Damaged or loose drag flights or buckets.

(g) Damaged chain, chain sprockets, or belts.

(h) Proper operating conditions.

(i) Oil or water leaks. Repair as required.

(j) Proper lubricant levels.

(2) Establish lubrication requirements and schedule as required by manufacturers instructions.

(3) Inspect scales for zero load balance.

b. Monthly: Item 4. Inspect for the following:

(1) Gear boxes, sheaves, rollers, shafts for proper lubrication, freedom of movement and bearing play.

(2) Screens for holes or plugging. Repair or clean as required.

(3) Structural frame for broken or bent parts and

loose or damaged joints.

(4) Proper alignment of pulleys and other parts.

(5) Proper operation of control and safety devices.

c. Semi-Annually: Item 5. Inspect for the following:

(1) Corrosion or erosion of hoppers, chutes, and gates.

(2) Lining and protective coatings for damage.

(3) Scale levers, knife edges, and bearings for wear or damage. Repair or replace as required.

(4) Concrete structures for cracks or other damage.

d. Annually: Item 6. Prepare applicable metal surfaces and repaint.

5-2l. ASH HANDLING EQUIPMENT.

Reference paragraph 2-20.

a. Daily.

(1) Inspect for the following:

(a) Piping leaks. Repair immediately.

(b) Proper operation of steam or mechanical exhauster.

(c) Proper operation of air wsher, if provided.

(d) Proper operation of ash gates and clinker grinders.

(e) Proper operation of automatic steam valves and automatic controls, ilncluding maintenance of correct steam pressue.

b. Quarterly.

(1) Item 2. Inspect conveyor piping, especially at elbows, for accumulated ash and erosion. Rotate, repair, or replace as necessary.

(2) Item 3. Inspect steam exhauster for corrosion and erosion.

(3) Item 4. Inspect wsher internals for wear, ash accumulation, and nozzle condition. Clean and repair as necessary.

5-22. OIL BURNERS.

Reference paragraphs 2-2l and 3-18.

a. Daily.

(1) Inspect for the following hourly:

(a) Oil, steam, or air leaks. Repair immediately.

(b) Unburned oil deposits and overheating of burner parts.

(c) Burner flame for proper shape, color and stability.

(d) Proper operating pressures and temperatures.

(2) Remove and clean the oil atomizer.

(3) Clean burner exterior.

(4) Follow the established schedule for cleaning burner strainers.

b. Annually.

(1) Item 5. Completely remove and clean the burner and igniter.

(2) Item 6. Inspect all air register and burner parts for freedom of movement, warpage and wear. Repair or replace as required. Adjust all parts for proper operation. The services of a burner servicemen may be required.

(3) Item 7. Replace atomizer tips or nozzles that have been in normal service with new tips or nozzles.

(4) Item 8. Calibrate burner pressue and t emperature gages.

5-23. OIL HANDLING EQUIPMENT.

Reference paragraphs 2-22 and 3-l8.

a. Daily.

(1) Inspect for the following:

(a) Oil, steam water, or air leaks. Repair immediately.

(b) Proper operation of traps, controls, and instrumentation.

(c) Proper operating pressures, temperatures, and levels.

(2) Clean equipment as required.

(3) Establish a schedule for cleaning strainers.

(4) Inspect and maintain pumps as outlined in paragraphs 5-34, 5-35, and 5-36.

b. Annually.

(1) Item 5. Inspect and clean heaters and tanks internally and externally. Inspect carefully for corrosion, erosion, pitting, plugged tubes, damaged baffles, sludge deposits, water accumulations, and scale deposits.

(2) Item 6. Inspect for damage to protective coatings or paint. Repair or repaint as required.

(3) Item 7. Test relief valve settings and operation.

(4) Item 8. Clean, inspect, and calibrate all controls and instrumentation.

5-24. GAS BURNERS.

Reference paragraphs 2-23 and 3-l9.

a. Daily. Inspect for the following hourly:

(1) Gas or air leaks. Repair immediately.

(2) Proper gas and air pressures.

(3) Burner flame for proper shape, color, and stability.

(4) Overheating or binding of burner parts.

b. Annually.

(l) Item 2. Completely remove and clean the burner and igniter.

(2) Item 3. Inspect all burner parts for freedom of movement, warpage, and wear. Inspect gas nozzles. Repair or replace as required. Adjust all parts for proper operation. The services of a burner serviceman may be required.

(3) Item 4. Calibrate burner pressure gages.

5-25. FEEDWATER/DRUM LEVEL CONTROLS.

Reference paragraph 2-25. a. Daily.

(1) Inspect for water leaks. Repair immediately.

(2) Observe operation of all control devices. Report and repair any malfunction immediately.

(3) Establish a lubrication schedule for all components in the control system in accordance with manufacturers recommendations.

b. Annually.

(1) Item 4. During the boiler overhaul, or more often if necessary, clean and inspect all control components. Look for signs of corrosion, erosion, or wear and for deposits, leaks, and defective parts. Repair as required.

(2) Item 5. Check settings, adjustments, and operation of all components.

5-26. COMBUSTION CONTROLS.

Reference paragraphs 2-26 and 3-20.

a. Daily.

(1) Inspect for air, oil, gas and water leaks. Repair immediately.

(2) Blow down compressed air drip legs and filters.

(3) Check jackshafts, dampers and linkages for slippage and freedom of movement.

(4) Inspect for stable and proper operation.

(5) Clean exterior of controls.

(6) Establish lubrication requirements and schedule in accordance with the manufacturers instructions.

b. Monthly: Item 7. Replace or clean all system filters.

c. Annually.

(1) Item 8. Inspect and completely clean all control devices internally. Replace any worn, corroded, or damaged parts.

(2) Item 9. Test for correct calibration. Adjust as required.

(3) Item 10. Test control settings under operating conditions. Optimize control function to improve plant efficiency.

(4) Item 11. Obtain the assistance of a fully trained combustion control service engineer as required to calibrate, clean and adjust the controls.

5-27. BOILER SAFETY CONTROLS.

Reference paragraphs 2-27 and 3-21.

a. Daily.

(1) Inspect all safety controls for leaks and cleanliness. Repair and clean immediately.

(2) Blow down the water column, gage glass, and low water fuel cutoff each shift. Test function.

b. Monthly.

(1) Item 3. Inspect all safety controls for such problems as dirty switch contacts, defective diaphragms or sensing elements, loose wires, dirty flame scanner lens or flame rod. Clean or repair immediately.

(2) Item 4. Test all safety controls for proper calibration and operation.

5-28. INSTRUMENTATION.

Reference paragraph 2-28.

a. Daily.

(1) Inspect for leaks. Repair immediately.

(2) Check for proper operation. Report any malfunction. Only trained personnel should place in service, remove from service, calibrate, or maintain instruments.

(3) Inspect for undue vibration, broken glass, lighting, and readability.

b. Annually. Once a year, or more often if necessary, make a thorough inspection of all instruments and gages for corrosion, deposits, or other defects. Item 4. Inspect carefully for the following:

(1) Ruptured or distorted pressue parts.

(2) Incorrect calibrations or adjustments.

(3) Badly worn pins or bushings.

(4) Damaged or burned thermocouple wire insulation.

(5) Leaking or damaged diaphragms, bellows, and gaskets.

(6) Mercury separations in thermometers.

(7) Loose pointers.

(8) Broken balance-arm screws.

(9) Plugged piping or tubing.

(10) Broken or damaged adjustment assemblies.

(11) Defective clockwork mechanism or electric motor operation.

5-29. MECHANICAL COLLECTORS.

Reference paragraph 2-32.

a. Daily.

(1) Observe draft gage readings and compare with normal readings for that operating condition.

(2) Check dust level in hopper to ensure hoppers are being emptied on a regular basis.

b. Quarterly. At the time of boiler outage, inspect for the following:

(1) Item 3. Check all gasketed joints for leaks. Replace damaged or defective gaskets as required.

(2) Item 4. Check the interior of dust collector for caked deposits, corrosion, erosion, loose parts, and other damage. Clean and repair as required.

(3) Item 5. Check the exterior of dust collector for damaged parts, paint, corrosion, etc. Clean and repair as required.

c. Annually: Item 6. Paint the entire assembly.

5-30. STACKS.

Reference paragraph 2-40.

a. Daily: Inspect for possible defects, leaks, damage, deterioration of lining, cracks, or settlement in foundation.

Report promptly any such observation.

b. Quarterly.

(1) Item 2. Make a more thorough examination of the chimney exterior using high powered binoculars quarterly or after every severe storm to look for cracks, spalls, corrosion, loose guy wires (if provided), damaged lightning rod and connectors, loose parts, etc.

(2) Item 3. Remove soot and fly-ash accumulation from base of stack.

(3) Item 4. Clean accumulation of soot and fly ash from connecting flues and inspect them for corrosion, erosion, and moisture. If moisture is found, clean more frequently. Remove the cause of water formation if possible.

c. Semi-Annually: Item 5. Carefully examine stack supports for corrosion, cracking, or movement of anchor blocks, and proper guy wire tension. Check for corrosion of the ladder.

d. Annually: Item 6. Clean and inspect the stack internally and externally. Inspect lightning rod tips and ground connections. Paint.

5-3l. ZEOLITE WATER SOFTENERS.

Reference paragraph 4-6a and 4-l6b.

a. Daily.

(1) Check for the following:

(a) Flow rates. Service, backwash, regenerant solution, and rinse rates should be carefully maintained.

(b) Adherence to manufacturers instructions for length of time for backwash, regeneration, and rinse operations.

(c) Proper operation of flow regulators, meters, pressure gages, temperature indicators.

(d) Chemical or water leaks.

(e) Hardness of water leaving softener to determine when to regenerate.

(f) Density of brine.

(g) Sump for zeolite carryover.

(2) Establish lubrication requirements and schedule in accordance with manufacturers recommendations.

b. Semi-Annually.

(1) Item 3. Inspect ion exchange vessel, valves, and piping for corrosion, rust, and peeling of paint.

(2) Item 4. Drain and internally inspect the ion exchange vessel for loss of resin, dirt, slime, or oil fouling of the bed, uneven bed, or corrosion or erosion in distributor piping.

c. Annually: Item 5. Calibrate instruments annually or more often as required.

5-32. HOT LIME-SODA SOFTENERS.

Reference paragraph 4-6b and 4-l6b.

a. Daily.

(1) Check for the following:

(a) Alkalinity and hardness several times each day to determine proper chemical additions.

(b) Chemical feed pump for operation.

(c) Plugging of feed lines.

(d) Chemical proportioner for operation.

(e) Temperature of water in reaction tank to verify heater function. Temperature should be greater than 212° F at sea level.

(f) Heater vent for proper venting.

(g) Live steam makeup valve for operation and pressure control.

(h) Pressure differential across filters to determine necessity of backwashing.

(i) Chemical solution tank. Add chemicals as required.

(j) All lilnes and valves for leakage. Repair or replace immediately.

(2) Blow down rection tank daily or more often according to sludge accumulation.

(3) Lubricate motors and pumps according to manufacturers directions and schedule.

b. Monthly.

(1) Item 4. Clean chemical solution tank. Clean outlet strainer.

(2) Item 5. Clean and flush chemical feed pump.

(3) Item 6. Lubricate and adjust chemical proportioner.

c. Semi-Annually.

(1) Item 7. Open and clean heater. Level and adjust trays and spray nozzles. Clean and drain vent condenser. Repack and reseat live steam regulator valve. Check diaphragm in regulator and replace if worn. Adjust regulator. Repack and reseat water inlet control valve.

(2) Item 8. Open, examine, clean, and recharge filters in accordance with manufacturers recommendations.

d. Annually.

(1) Item 9. Drain, open, and clean reaction tank. Repair or replace damaged insulation. If corrosion is excessive on interior of tank, scrape thoroughly and apply protective paint or other similar coating. If exterior is exposed, paint after thoroughly cleaning.

(2) Item 10. Dismantle, clean, overhaul, and repack pumps.

(3) Item 11. Repack valves.

(4) Item 12. Paint exposed surfaces.

5-33. DEAERATING HEATERS AND DEAERATORS.

Refernce paragraph 4-6h and 4-l6c.

a. Daily.

(1) Check for correct operation of relief valve, steam pressure reducing valve, overflow, controls, alarms, and

steam pressure and temperature indicators. Report any malfunctions immediately.

(2) Inspect for steam and water leaks. Repair immediately.

b. Annually: Item 3. Once a year, or more often under severe service conditions, clean the unit and inspect the following:

(1) Spray valves for corrosion, erosion, scaling, and proper seating.

(2) Water discharge nozzles for clogging, corrosion, and wear.

(3) Trays (on tray type units). Remove and inspect for corrosion, warping, and scaling.

(4) Oil separator. Inspect interior of heater for evidence of oil, corrosion, or scaling.

(5) Condition of relief, steam prssure reducing, float, vent, and overflow valves.

(6) Condition of gage glass, controls, alarms, and instruments.

(7) Condition of piping and valves.

(8) Vent condenser. Open and check for corrosion, wear, clogging of tubes, and scaling.

(9) Condition of insulation. Check for cracks and peeling.

5-34. PUMPS.

Reference paragraph 2-37.

a. Daily. Inspect for the following hourly:

(1) Unusual noise or vibration.

(2) Electric motors for overheating.

(3) Hot bearings.

(4) Abnormal suction or discharge pressures.

(5) Hot stuffing box.

(6) Abnormal leakage through glands/seals.

b. Monthly. Item 2. Inspect all external gear and bearing housings for correct lubricant condition. Establish lubrication requirements and schedule in accordance with the manufacturers recommendations.

c. Annually. Item 3. Completely disassemble, clean, and inspect the pump. Check for the following:

(1) Excessive clearances.

(2) Hot and cold alignment.

(3) Corrosion or erosion of parts.

(4) Excessive wear of shafts, sleeves, bearings, and seals.

(5) Cracks, scrapes, wastage, or corrosion of gear teeth if provided.

5-35. CENTRIFUGAL PUMPS.

Reference paragraph 2-37b.

a. Daily: Inspect for the following hourly:

(1) Abnormal vibration and noise.

(2) Abnormal pressure and flow conditions.

(3) Excessive or inadequate packing leakage.

(4) Hot bearings.

(5) Hot stuffing box.

b. Semi-Annually.

(1) Item 2. Check alignment of pump and driver with the unit at stand-still and normal operating temperature.

(2) Item 3. Check shaft sleeves for scoring.

(3) Item 4. Replace packing if required.

(4) Item 5. Drain the oil from oil-lubricated bearings, flush, and refill with clean oil.

(5) Item 6. Check grease-lubricated bearings. Do not overgrease the bearings. When adding grease, remove drain plug or use a safety fitting to prevent overgreasing.

c. Annually: Item 7. Completely disassemble, clean, and inspect the pump. Check for the following:

(1) Wearing ring clearances according to manufacturers instructions. Diametric clearance between 0.005 and 0.025 inch is usual.

(2) Bearing wear and clearances. Overhaul if required, according to manufacturers instructions.

(3) Shaft for scoring, corrosion, or wear at seals, and alignment.

(4) Impellers for corrosion, erosion, or excessive wear.

(5) Calibrate pressure gages, thermometers, and flowmeters.

(6) Suction and discharge strainers for cleanliness.

5-36. RECIPROCATING PUMPS.

Reference paragraph 2-37c.

a. Daily.

(1) Inspect for the following hourly:

(a) Abnormal speed.

(b) Improper stroke length.

(c) Defective operation of lubricator.

(d) Ineffective operation of governor.

(e) Improper action of the air chamber.

(f) Steam and water leaks.

(2) Establish lubrication requirements and schedule in accordance with manufacturers instructions.

b. Monthly: Item 3. Inspect for the following:

(1) Scoring of piston rods.

(2) Binding of valve operating mechanism.

(3) Lost motion.

(4) Tilted glands in stuffing boxes.

(5) Defective condition of strainers.

c. Annually:

(1) Item 4. Dismantle the pump once a year or more often if required; clean and inspect the poump.

(2) Item 5. Check the following in the liquid end:

(a) Condition of valves, springs, and retaining bolts.

(b) Condition of cylinder liner.

(c) Piston rings or packings.
(d) Piston rod packing.
(e) Relief valve, if used, and setting.
(f) Alignment.
(g) Strainers, if used.

(2) Item 6. Also look for corrosion, erosion, or excessive wear of parts, and for transmission of strains from piping to pump.

(3) Item 7. Check the following in the steam end:
(a) Condition of pistons and piston rings, slide valves and seals.
(b) Alignment.
(c) Clearance between piston and cylinder liner.
(d) Lubricator.
(e) Governor.

(4) Item 8. Check for plugged steam passages in steam chest, scoring of shoulders or cyliners, corrosion, erosion, and excessive wear of parts.

(5) Item 9. Calibıate instruments.

(6) Item 10. Replace packings.

5-37. STEAM INJECTORS.

Reference paragraph 2-37e.

a. Daily.

(1) Inspect for steam and water leaks. Repair as required.

(2) Check for correct feedwater flow.

(3) Check for correct temperature and pressure readings.

(4) Check for erratic overflow.

b. Annually: Item 5. Dismantle injector. Clean and inspect for the following:

(1) Injectors for corrosion, erosion, excessive wear, and clogging passages. Pay particular attention to nozzles.

(2) Valves for corrosion, excessive wear, and leakage. Check packing.

(3) Piping for corrosion, scaling, and erosion.

(4) Insulation.

5-38. STEAM TURBINES (NON-CONDENSING).

Reference paragraph 2-41. Institute preventive maintenance schedule in accordance with manufacturers recommendations. The following program is suggested for a singel stage impulse non-condensing steam turbine typically used at Army installations to drive auxiliary equipment.

a. Daily.

(1) Inspect for the following:
(a) Proper oil levels, pressures, and temperatures.
(b) Hot bearings.
(c) Dirty or emulsified oil.
(d) Unusual noise or vibration.
(e) Steam, water and oil leaks. Repair as necessary.
(f) Proper operation of governor under varying load.
(g) Proper operation of all ilnstruments, gages, and throttle valve.

(2) Establish lubrication requirements and schedule in accordance with manufacturers instructions.

b. Weekly.

(1) Item 3. Blow down steam strainer connection.

(2) Item 4. Lubricate governor and overspeed trip linkages.

(3) Item 5. Trip emergency valve by hand trip lever to check its operability.

c. Monthly.

(1) Item 6. Change bearing oil and clean reservoir.

(2) Item 7. Make visual inspection of governor parts, bearings, and linkage for lost motion.

(3) Item 8. Check coupling for looseness, wear, and alignment.

d. Annually: Item 9. Make a thorough inspection of the unit after the first year of operation. Subsequent internal inspection intervals should be based upon operating conditions and the operating record of the machine. Follow manufacturers recommendations for such inspections. The following may be adopted as guidelines for an annual overhaul:

(1) Dismantle speed governor and check and rectify play in linkage.

(2) Check overspeed trip governor for proper opoeration. Repair if necessary.

(3) Clean and examine governor valve, bushing, valve stem, etc. Replace stem packing.

(4) Check thrust bearing for end play.

(5) Clean and examine turbine blades and shrouds for cracks, damage, erosion, and debris.

(6) Clean steam strainer.

(7) Clean and inspect packing rings for damage and axial rubs.

(8) Inspect turbine bearings. Change if necessary.

5-39. AIR COMPRESSORS.

Reference paragraph 2-45.

a. Daily.

(1) Inspect for the following:
(a) Unusual noise or vibration.
(b) Abnormal temperature and prssure of compressed air, cooling water, or lubricating oil.
(c) Proper operation of unloader.
(d) Hot bearings and stuffing box.
(e) Correct lubricating oil level and oil consistency.

(2) Establish lubrication requirements and schedule in accordance with manufacturers recommendations.

b. Quarterly: Item 3. Inspect for the following:

(1) Compressor valves for wear, dirt, and improper seating.

(2) Operation of all safety valves.

(3) Belts for tension, wear, and deterioration.

(4) Cleanliness of air intake filter.

(5) Tightness of cylinder head bolts and gaskets.

c. Annually.

(1) Item 4. Check cylinders for wear, scoring, corrosion, and dirt.

(2) Item 5. Inspect pistons and rings for leakage, wear, scoring, security to the piston rod, and head clearances.

(3) Item 6. Inspect crank shaft and crank shaft bearings for wear and proper operation.

(4) Item 7. Check alilgnment of the compressor with respect to the driver.

5-40. STEAM TRAPS.

Reference paragraph 2-46. Establish a comprehensive and coordinated maintenance and inspection program for all steam traps, strainers, and separators. As a minimum, the following must be done for central boiler plants.

a. Daily: Inspect the traps, strainers, and separators for the following:

(1) Piping leaks. Repair as necessary.

(2) Correct operation.

(3) Abnormal pressure drop across strainers.

(4) Unusual accumulations of foreign matter in strainer baskets.

(5) Unusual and excessive discharge of condensate and oil from separators.

(6) Damage to insulation at traps. Repair as necessary.

b. Monthly.

(1) Item 2. Blow down steam trap to eliminate dirt accumulations.

(2) Item 3. Open the air vents on float traps to vent accumulated air.

(3) Item 4 Test traps for correct operation.

c. Annually.

(1) Item 5. Completely disassemble all steam traps and inspect them carefully for the following:

(a) Cracked, corroded, broken, loose, or worn parts.

(b) Excessive wear, grooving, and wire drawing of valves and seats.

(c) Defective bellows, buckets, or floats.

(2) Item 6. Replace or repair all defective gaskets, linkages, and orifices.

(3) Item 7. Reassemble and test for proper operation.

5-41. ELECTRIC MOTORS.

Reference paragraph 2-42. Also reference TM 5-683 entitled Facilities Engineering Electrical Interior Facilities.

a. Daily.

(1) Inspect for the following:

(a) Cleanliness.

(b) Overheating.

(c) Hot bearings.

(d) Correct lubrication.

(e) Proper operation of instruments and controls.

(f) Unusual noise or vibration.

(g) Continuous or excessive sparking at commutator or brushes.

(h) Loose belts, if provided.

(2) Establish lubrication and motor maintenance in accordance with manufacturers recommendatins.

b. Annually.

(1) Item 3. Inspect squirrel cage rotors for broken or loose bars. Check for loose or broken fan blades.

(2) Item 4. Thoroughly inspect all ball, roller, and sleeve bearings for wear and dirt.

(3) Item 5. Check and record insulation resistance.

(4) Item 6. Check windings for dirt, moisture, cracks, and loose wedges.

(5) Item 7. Check coupling alignment.

5-42. FORCED DRAFT AND INDUCED-DRAFT FANS.

Reference paragraphs 2-38 and 2-39.

a. Daily.

(1) Inspect for the following:

(a) Abnormal noises.

(b) Abnormal vibration.

(c) Overheating of drive.

(d) Abnormal bearing temperature.

(e) Condition of oil and bearing oil level.

(f) Proper flow and temperature of bearing-cooling water.

(g) Freedom of damper motion.

(2) Establish lubrication requirements and schedule in accordance with manufacturers recommendations.

b. Quarterly.

(1) Item 3. Examine water cooling system for corrosion and clogging.

(2) Item 4. Clean rotor and casing and inspect for corrosion, erosion, and damage. Check clearances between rotor and casing.

(3) Item 5. Check alignment of shaft and coupling; inspect coupling.

(4) Item 6. Check condition of foundation and tightness of bearing and foundation bolts. Defective foundation or loose bolts may promote heavy vibration.

(5) Item 7. Inspect bearings.

c. Annually: Item 8. Annually, or more often if required, inspect and perform the following maintenance work:

(1) Complete by overhaul bearings.

(2) Clean and flush cooling system.

(3) Repair or replace fan blades, as required. After replacing blades, rebalance rotor.

(4) Repair or replace defective parts.

(5) Repair insulation.

5-43. COMMAND INSPECTIONS.

Command inspections are a function of commanding officers. They are made to determine the general condition and effective use of central boiler plant equipment, causes of neglect or carelessness, and need for additional instruction or training of operating personnel. Command inspections may be formal, informal, or spot checks.

a. Procedure. Command inspections are made on accessible central boiler plant equipment at any time that causes the least possible interference with boiler plant routine. All equipment, accessories, and connections are checked during formal inspections; equipment is selected at random for informal inspections and spot checks. Inspectors look for the following:

(1) Cleanliness of equipment, pipes, walks, floors, walls, and instruments.

(2) Any leaks from water, steam, oil, or air equipment.

(3) Neat and orderly storage tools, spare parts, upplies, and fuel.

(4) Deficiencies of equipment, working order of parts.

(5) Prompt notification to the Director of Engineering and Housing of all opoerating deficiencies.

(6) Methods and procedures used in hazardous opertions.

b. Follow-Up. After inspections have been completed, personnel are advised of the deficiencies and irregularities noted.

5-44. TECHNICAL INSPEZCTION.

Technical inspections are made by the Director of Engineering and Housing or designated personnel of his organizatrion to determine the general condition of boiler plant equipment, effectiveness of preventive maintenance , and need for additional instruction or training of maintenance personnel.

a. Procedure. Boiler plant equipment is selected at random and inspected without previous notification so that the overall condition of equipment and efficiency of maintenance personnel can be determined. Technical inspections are preferably made while equipment is being dismantled for routine inspection. In thoroughness, the technical inspection should equal inspections made by insurance or other authorized inspecting agencies. The following are checked at each piece of boiler plant equipment inspected.

(1) All items included in command inspections. (See paragraph 5-43.)

(2) Adequacy of preventive maintenance as it is being performed.

b. Follow -Up. On completion of the technical inspection, the Director of Engineering and Housing will take the steps necessary to correct indicated deficiencies in preventive maintenance inspection and service procedures. He will arrange to have any indicated maintenance work done at once.

5-45. MAJOR ARMY COMMAND INSPECTIONS.

Major Army Command Inspections are made by technical personnel to determine effectiveness of preventive maintenance and to ensure uniform procedures at all posts. They include examination of preventive maintenance inspection records.

a. General Inspections. Technical personnel make general inspections at least four times a year. Inspectors check the following:

(1) Preventive maintenance record system.

(2) Familiarity of maintenance personnel with equipment duties.

(3) Promptness of corrective action when Director of Engineering and Housing is notified of defects.

b. Follow-Up. Errors and oversights are reported to the proper authority. The Major Army Command maintains suitable records of inspections. These records include a list of equipment inspected, findings, recommendations, and other pertinent data.

Appendix D: Fort Wainwright Cost Details

		2006	2006	2007	2007	2008	2008	2009	2009	2010	2010
	Boiler repairs	Material	Labor	Material	Labor	Material	Labor	Material	Labor	Material	Labor
	All bottom ash -- ash pit outside doors 4 per boiler total 24	4,800	25,200	4,800	25,200	4,800	25,200	4,800	25,200	4,800	25,200
	All bottom ash -- ash pit inside doors and all tubing 4 ea --total 24	4,000	17,000	4,000	17,000	4,000	17,000	4,000	17,000	4,000	17,000
	All ash grinders--4 per boiler--total 24	503,800	93,600	503,800	93,600	503,800	93,600	503,800	93,600	503,800	93,600
	All bottom slide gates per boiler--4 per boiler --- total 24	12,000	25,200	12,000	25,200	12,000	25,200	12,000	25,200	12,000	25,200
	All bottom ash pipe sections---total in floor---60	6,000	6,400	6,000	6,400	6,000	6,400	6,000	6,400	6,000	6,400
	All bottom ash pipe sections---total above floor 37	6,000	6,400	6,000	6,400	6,000	6,400	6,000	6,400	6,000	6,400
	All gate air operated valves---15 total	17,000	5,400	17,000	5,400	17,000	5,400	17,000	5,400	17,000	5,400
	All hydraulic tubing and cooling lines for ash door controls and cooling	2,400	20,200	2,400	20,200	2,400	20,200	2,400	20,200	2,400	20,200
	Hydraulic pressure unit and pumps (two high pressure)	8,000	2,200	8,000	2,200	8,000	2,200	8,000	2,200	8,000	2,200
	Hydraulic reservoir kidney pump	3,000	1,000	3,000	1,000	3,000	1,000	3,000	1,000	3,000	1,000
	All fly ash swing gates--3each boiler---18 total	18,000	19,000	18,000	19,000	18,000	19,000	18,000	19,000	18,000	19,000
	Boiler blow down flash tank and all connecting lines	6,000	17,000	6,000	17,000	6,000	17,000	6,000	17,000	6,000	17,000
	Waste pump with motor for flash tank	9,600	3,800	9,600	3,800	9,600	3,800	9,600	3,800	9,600	3,800
	Air cushion tank for ash door hydraulic lifts--1 ea boiler--total 6	3,000	2,600	3,000	2,600	3,000	2,600	3,000	2,600	3,000	2,600
	All swing gate riddling ash gates 2 ea boiler---total 12	7,600	19,600	7,600	19,600	7,600	19,600	7,600	19,600	7,600	19,600

		2006	2006	2007	2007	2008	2008	2009	2009	2010	2010
	Boiler repairs	Material	Labor	Material	Labor	Material	Labor	Material	Labor	Material	Labor
	All air regulating valves and solenoids for riddling system 2 ea	1,600	800	1,600	800	1,600	800	1,600	800	1,600	800
	Riddling ash line sections total 64	18,000	33,800	18,000	33,800	18,000	33,800	18,000	33,800	18,000	33,800
	All six complete stokers on all six boilers	100,320	4,000	100,320	4,000	100,320	4,000	100,320	4,000	100,320	4,000
	All six boiler coal bed, rolling grates	24,000	31,600	24,000	31,600	24,000	31,600	24,000	31,600	24,000	31,600
	All six boiler stoker cooling water supply lines and valves	24,000	25,400	24,000	25,400	24,000	25,400	24,000	25,400	24,000	25,400
	All stoker draft tubes/six per boiler/six boilers	36,000	15,200	36,000	15,200	36,000	15,200	36,000	15,200	36,000	15,200
	All boiler and mud drum blow down valves per boiler, six boilers, 56 valves total	23,200	24,400	23,200	24,400	23,200	24,400	23,200	24,400	23,200	24,400
	All boiler and mud drum blow down seatless valves, six boilers, 56 total valves	23,200	24,400	23,200	24,400	23,200	24,400	23,200	24,400	23,200	24,400
	All cinder re-injection tubes on all six boiler	6,000	5,000	6,000	5,000	6,000	5,000	6,000	5,000	6,000	5,000
	All cinder re-injection hopper slide gates on all six boilers	3,000	6,400	3,000	6,400	3,000	6,400	3,000	6,400	3,000	6,400
	All cinder re-injection fans ---- 1ea ---- six boil-ers---six total	24,000	12,600	24,000	12,600	24,000	12,600	24,000	12,600	24,000	12,600
	1 ea under grate zone louvers and control arm per boiler	30,000	19,000	30,000	19,000	30,000	19,000	30,000	19,000	30,000	19,000
	1 ea blast gate louver and control arm per boiler	30,000	19,000	30,000	19,000	30,000	19,000	30,000	19,000	30,000	19,000
	1 each forced draft motor per boiler -- total 6	18,000	12,600	18,000	12,600	18,000	12,600	18,000	12,600	18,000	12,600
	100 safety glass windows and panes	6,000	10,600	6,000	10,600	6,000	10,600	6,000	10,600	6,000	10,600
	De-superheater in #4 lateral	6,000	6,400	6,000	6,400	6,000	6,400	6,000	6,400	6,000	6,400
	Overhauls/tube replacements										

		2006	2006	2007	2007	2008	2008	2009	2009	2010	2010
	Boiler repairs	Material	Labor	Material	Labor	Material	Labor	Material	Labor	Material	Labor
	Subtotal boiler repairs	984,520	515,800	984,520	515,800	984,520	515,800	984,520	515,800	984,520	515,800
	Turbine repairs										
	St 1 maintenance and repair	175,000	25,000	85,000	15,000	100,000	25,000	103,750	25,000	105,113	27,500
	St 1 overhaul									900,000	100,000
	St 3 maintenance and repair	175,000	25,000	85,000	15,000	100,000	25,000	103,750	25,000	105,113	27,500
	St 3 overhaul										
	St 4 maintenance and repair	175,000	25,000	85,000	15,000	100,000	25,000	103,750	25,000	105,113	27,500
	St 4 overhaul							900,000	100,000		
	St 5 maintenance and repair	175,000	25,000	85,000	15,000	100,000	25,000	103,750	25,000	105,113	27,500
	St 5 overhaul					900,000	100,000				
	Subtotal steam turbine	700,000	100,000	340,000	60,000	1,300,000	200,000	1,315,000	200,000	1,320,452	210,000
	Balance of plant										
Coal handling systems											
COAL	Ball bearing greasing	800	8,000	800	8,000	800	8,000	800	8,000	800	8,000
COAL	Inspect/replace crusher hammer and suspension bars	7,000	5,400	7,000	5,400	7,000	5,400	7,000	5,400	7,000	5,400
COAL	Inspection/replacement of components that suffer most from the erosion and abrasion wear (track grizzly, apron, etc.)	4,000	5,400	4,000	5,400	4,000	5,400	4,000	5,400	4,000	5,400
COAL	Inspection/replacement of belt cleaner and plows, idlers, pulley assemblies, conveyor and feeding belting, storage pile discharger, chutes, magnetic separator, belt scale, duct collectors, exhaust fan	5,000	12,800	5,000	12,800	5,000	12,800	5,000	12,800	5,000	12,800

		2006	2006	2007	2007	2008	2008	2009	2009	2010	2010
	Boiler repairs	Material	Labor	Material	Labor	Material	Labor	Material	Labor	Material	Labor
COAL	Major inspection and repair activities	40,000	85,000	40,000	85,000	40,000	85,000	40,000	85,000	40,000	85,000
Ash systems (including baghouse/id fan/env cont)											
ASH	Replace all bottom ash pipe sections in vertical lines 7 stories	8,000	20,160	8,000	20,160	8,000	20,160	8,000	20,160	8,000	20,160
ASH	Replace ash control system panel and controls	10,000	8,400	10,000	8,400	10,000	8,400	10,000	8,400	10,000	8,400
ASH	Replace fly ash line sections	2,400	5,100	2,400	5,100	2,400	5,100	2,400	5,100	2,400	5,100
ASH	Ball bearing greasing	800	8,800	800	8,800	800	8,800	800	8,800	800	8,800
ASH	Inspection for vacuum leaking and erosion/elbows replacement	3,000	4,200	3,000	4,200	3,000	4,200	3,000	4,200	3,000	4,200
ASH	Screw conveyor liner inspection/replacement	1,500	1,600	1,500	1,600	1,500	1,600	1,500	1,600	1,500	1,600
ASH	Valve liner inspection/replacement	1,000	4,200	1,000	4,200	1,000	4,200	1,000	4,200	1,000	4,200
ASH	Replacement of filter bags and other components that suffer most from dust exposure (assume 100 bags)	1,400	5,200	1,400	5,200	1,400	5,200	1,400	5,200	1,400	5,200
ASH	Major inspection and repair activities	40,000	35,000	40,000	35,000	40,000	35,000	40,000	35,000	40,000	35,000
Steam piping											
STEAM	Replace (1) 100 lb pressure regulating valve (steam)	3,000	2,200	3,000	2,200	3,000	2,200	3,000	2,200	3,000	2,200
STEAM	Replace (1) 50 lb pressure regulating valve (steam)	1,800	600	1,800	600	1,800	600	1,800	600	1,800	600
STEAM	Replace (1) two story 400lb auxiliary steam line and all connecting piping	29,000	13,600	29,000	13,600	29,000	13,600	29,000	13,600	29,000	13,600
STEAM	Replace 50 lb steam prv #14	1,800	600	1,800	600	1,800	600	1,800	600	1,800	600
STEAM	Replace 10 lb steam prv	1,400	400	1,400	400	1,400	400	1,400	400	1,400	400

		2006	2006	2007	2007	2008	2008	2009	2009	2010	2010
	Boiler repairs	Material	Labor	Material	Labor	Material	Labor	Material	Labor	Material	Labor
STEAM	Replace 200 lb steam prv	2,000	600	2,000	600	2,000	600	2,000	600	2,000	600
STEAM	Inspect/replace 100 psig system 18" bellow expansion joints	600	800	600	800	600	800	600	800	600	800
STEAM	Prv, control, shutoff and check valves inspection/maintenance	1,000	2,200	1,000	2,200	1,000	2,200	1,000	2,200	1,000	2,200
STEAM	Replacement of steam piping	25,000	5,000	25,000	5,000	25,000	5,000	25,000	5,000	25,000	5,000
******	Nde inspection of tees, elbows, piping, and valve discharge areas	12,500	2,500	12,500	2,500	12,500	2,500	12,500	2,500	12,500	2,500
Feedwater / condensate sys											
FW	Fw pumps inspection and maintenance	3,077	9,692	3,077	9,692	3,077	9,692	3,077	9,692	3,077	9,692
FW	Fw piping replacement	15,000	2,000	15,000	2,000	15,000	2,000	15,000	2,000	15,000	2,000
FW	Fw piping nde	2,000	-	2,000	-	2,000	-	2,000	-	2,000	-
FW	Deaerator inspection and maintenance	914	2,400	914	2,400	914	2,400	914	2,400	914	2,400
CONDEN	Sodium cation polisher resin treatment (one unit at a time)	1,200	3,800	1,200	3,800	1,200	3,800	1,200	3,800	1,200	3,800
CONDEN	Sodium cation polisher resin replacement (one unit at a time)	1,200	3,800	1,200	3,800	1,200	3,800	1,200	3,800	1,200	3,800
CONDEN	Nde piping inspection in tees, elbows, valve discharges areas	1,250	-	1,250	-	1,250	-	1,250	-	1,250	-
CONDEN	Conden piping replacement	10,000	1,500	10,000	1,500	10,000	1,500	10,000	1,500	10,000	1,500
CONDEN	Pump inspection/maintenance	800	4,200	800	4,200	800	4,200	800	4,200	800	4,200
Cooling sys		-	-	-	-	-	-	-	-	-	-
Aux COOL	Replace auxiliary cooling water system skids motors and pumps	8,000	4,200	8,000	4,200	8,000	4,200	8,000	4,200	8,000	4,200

		2006	2006	2007	2007	2008	2008	2009	2009	2010	2010
	Boiler repairs	Material	Labor	Material	Labor	Material	Labor	Material	Labor	Material	Labor
Aux COOL	Replace auxiliary cooling water system glycol tank and lines	2,000	2,200	2,000	2,200	2,000	2,200	2,000	2,200	2,000	2,200
		-	-	-	-	-	-	-	-	-	-
HVAC	Replace two air compressor fresh air fans and all duct work and motors	6,000	4,200	6,000	4,200	6,000	4,200	6,000	4,200	6,000	4,200
HVAC	Replace fresh air fans in east wall of turbine floor and duct work added	8,000	4,200	8,000	4,200	8,000	4,200	8,000	4,200	8,000	4,200
HVAC	Replace turbine floor offices and control room air circulation and conditioning systems (elements)	63,000	-	63,000	-	63,000	-	63,000	-	63,000	-
S AIR	Replace air compressors for plant operations and service air	30,000	3,200	30,000	3,200	30,000	3,200	30,000	3,200	30,000	3,200
S AIR	Replace air dryers---total 2	4,267	267	4,267	267	4,267	267	4,267	267	4,267	267
S AIR	Replace two stand by compressors	14,000	2,200	14,000	2,200	14,000	2,200	14,000	2,200	14,000	2,200
S AIR	Replace air cushion and moisture tanks 4 total	800	800	800	800	800	800	800	800	800	800
ACC	Fan	1,200	6,400	1,200	6,400	1,200	6,400	1,200	6,400	1,200	6,400
ACC	Motors	400	3,000	400	3,000	400	3,000	400	3,000	400	3,000
ACC	Gearbox	400	3,000	400	3,000	400	3,000	400	3,000	400	3,000
ACC	Vibration switches	600	600	600	600	600	600	600	600	600	600
ACC	Ejectors	400	3,000	400	3,000	400	3,000	400	3,000	400	3,000
ACC	Isolation valves	200	600	200	600	200	600	200	600	200	600
ACC	Pumps	600	1,800	600	1,800	600	1,800	600	1,800	600	1,800
ACC	Fin tube bundle	1,200	6,400	1,200	6,400	1,200	6,400	1,200	6,400	1,200	6,400
ACC	Major inspection and repair activities	-	-	-	-	-	-	-	-	-	-

		2006	2006	2007	2007	2008	2008	2009	2009	2010	2010
	Boiler repairs	Material	Labor	Material	Labor	Material	Labor	Material	Labor	Material	Labor
Water treatment											
W TREAT	Replace water treatment chemical tanks and systems--total 3	15,000	6,400	15,000	6,400	15,000	6,400	15,000	6,400	15,000	6,400
W TREAT	Replace pumps for water treatment chemicals 2 ea--total 6	3,000	2,600	3,000	2,600	3,000	2,600	3,000	2,600	3,000	2,600
W TREAT	Ro membrane cip procedure	120	440	120	440	120	440	120	440	120	440
W TREAT	Plate and frame heat exchanger cleaning	200	840	200	840	200	840	200	840	200	840
W TREAT	Pre-filtration skid media replacement (sand-anthracite)	1,000	2,200	1,000	2,200	1,000	2,200	1,000	2,200	1,000	2,200
W TREAT	Ro skid membrane replacement	2,000	4,200	2,000	4,200	2,000	4,200	2,000	4,200	2,000	4,200
W TREAT	Pump inspection/maintenance	-	-	-	-	-	-	-	-	-	-
W TREAT	Major inspection and repair activities	16,000		16,000		16,000		16,000		16,000	
WASTE	Replace waste water sump pumps --- 2 with motors	3,333	1,833	3,333	1,833	3,333	1,833	3,333	1,833	3,333	1,833
WASTE	Replace waste tank sump pumps and all lines connecting	6,000	4,200	6,000	4,200	6,000	4,200	6,000	4,200	6,000	4,200
WASTE	Replace waste tank --- 1000 gallon holding tank	1,000	400	1,000	400	1,000	400	1,000	400	1,000	400
WASTE	Replace sewage lift station complete--2---	8,000	4,200	8,000	4,200	8,000	4,200	8,000	4,200	8,000	4,200
WASTE	Replace waste oil / hazmat satellite system auxiliaries drums, pumps	2,000	4,200	2,000	4,200	2,000	4,200	2,000	4,200	2,000	4,200
WASTE	Replace waste pit sump pump	2,000	1,000	2,000	1,000	2,000	1,000	2,000	1,000	2,000	1,000
P WATER	Replace domestic water filter resin --- total three filters---	300	600	300	600	300	600	300	600	300	600
P WATER	Replace domestic water filter control valves w/control panel	3,000	2,200	3,000	2,200	3,000	2,200	3,000	2,200	3,000	2,200

		2006	2006	2007	2007	2008	2008	2009	2009	2010	2010
	Boiler repairs	Material	Labor	Material	Labor	Material	Labor	Material	Labor	Material	Labor
Instrument/control											
I&C	Replace all engineer stations for plant control room (control room, shift foreman office, fire floor)	3,000	1,584	3,000	1,584	3,000	1,584	3,000	1,584	3,000	1,584
I&C	Replace all control panels in control room for all plant auxiliaries.	50,000	13,200	50,000	13,200	50,000	13,200	50,000	13,200	50,000	13,200
I&C	Replace all plant control room pc's	1,500	1,584	1,500	1,584	1,500	1,584	1,500	1,584	1,500	1,584
I&C	Repair and/or replace transmitters, switches, sensors, etc.	13,500	1,150	13,905	1,185	14,322	1,220	14,752	1,257	15,194	1,294
I&C	Repair and/or replace dcs components	12,000	1,350	12,360	1,391	12,731	1,432	13,113	1,475	13,506	1,519
Electrical distribution											
EL	Demolish mcc 21- 2400 v panels	-	3,960	-	3,960	-	3,960	-	3,960	-	3,960
EL	Replace p 1 and p 2 breaker panels	10,000	3,168	10,000	3,168	10,000	3,168	10,000	3,168	10,000	3,168
EL	Replace p4, p5, p6, p8 breaker panels	20,000	6,336	20,000	6,336	20,000	6,336	20,000	6,336	20,000	6,336
EL	Replace 2400 volt panel and breakers with 4160 volt panel	-	-	-	-	-	-	-	-	-	-
EL	Demolish 4160 and 2400 volt cable tie (yel-low)	-	3,960	-	3,960	-	3,960	-	3,960	-	3,960
EL	Replace all light fixtures on ceiling of turbine room	2,500	7,920	2,500	7,920	2,500	7,920	2,500	7,920	2,500	7,920
EL	Replace all light fixtures on all electrical pan-els in turbine room	750	3,168	750	3,168	750	3,168	750	3,168	750	3,168
EL	Replace all light fixtures on all turbine panels in turbine room	-	-	-	-	-	-	-	-	-	-

		2006	2006	2007	2007	2008	2008	2009	2009	2010	2010
	Boiler repairs	Material	Labor	Material	Labor	Material	Labor	Material	Labor	Material	Labor
EL	Replace battery cells as needed in battery banks (north and south vaults) and 1 battery bank replacement	750	250	750	250	750	250	750	250	750	250
EL	Replace breakers for dc power and also rectifier	6,000	1,584	6,000	1,584	6,000	1,584	6,000	1,584	6,000	1,584
EL	Repair and/or replace electrical components	40,000	5,000	41,200	5,150	42,436	5,305	43,709	5,464	45,020	5,628
MAINT SHP	Maintenance shop equipment, small tools, etc.	15,000		15,450		15,914		16,391		16,883	
CONSUM	Maintenance consumables	40,000		41,200		42,436		43,709		45,020	
BOP	Subtotal balance of plant	657,461	400,746	661,076	400,971	664,800	401,203	668,635	401,442	672,585	401,688
	New technology										
	Computerized maintenance management system	32,000	68,000	20,000		20,000		20,000		20,000	
	Vibration analysis systems	24,000		2,000		2,000		2,000		2,000	
	Thermal imaging	19,500		2,000		2,000		2,000		2,000	
	Ultrasonic	12,000		2,000		2,000		2,000		2,000	
	Oil analysis	11,410		11,410		11,410		11,410		11,410	
	Subtotal new technology	98,910	68,000	37,410	-	37,410	-	37,410	-	37,410	-
CHPP	Subtotal chpp bare erected costs	2,440,891	1,084,546	2,023,006	976,771	2,986,730	1,117,003	3,005,565	1,117,242	3,014,967	1,127,488
	Owner's costs										
	Engineering @ 5%	122,045	54,227	101,150	48,839	149,336	55,850	150,278	55,862	150,748	56,374
	Project management	-		-		-		-		-	
	Subtotal bare erected costs and owner's costs	2,562,936	1,138,774	2,124,157	1,025,610	3,136,066	1,172,853	3,155,843	1,173,104	3,165,715	1,183,862

		2006	2006	2007	2007	2008	2008	2009	2009	2010	2010
	Boiler repairs	Material	Labor	Material	Labor	Material	Labor	Material	Labor	Material	Labor
	Project contingency	-		-		-		-		-	
	Rate	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%
	Value	640,734	284,693	531,039	256,402	784,017	293,213	788,961	293,276	791,429	295,966
	Total plant maintenance cost (excluding staffing)	3,203,670	1,423,467	2,655,196	1,282,012	3,920,083	1,466,067	3,944,804	1,466,380	3,957,144	1,479,828
	Total plant labor cost (recommended staffing)	-	1,098,829	-	1,098,829	-	1,098,829	-	1,098,829	-	1,098,829
	Total plant cost	3,203,670	2,522,296	2,655,196	2,380,841	3,920,083	2,564,896	3,944,804	2,565,209	3,957,144	2,578,657

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14. ABSTRACT

The Technology Requirements Study for a new Central Heating and Power Plant (CHPP) at Fort Wainwright, Alaska (FWA) (Vavrin et al. 2006) recommended that if the option for a new CHPP were to be pursued, among the tasks suggested for further analysis was to determine predictive maintenance requirements and new technologies for the existing plant. This study was undertaken to develop a Preventative Maintenance (PM) assessment that includes a maintenance program overview for the major systems in the existing CHPP. The assessment entailed: (1) an identification of shortcomings and deficiencies of existing procedures and processes,
(2) recommendations to overcome shortcomings and deficiencies, (3) development of a maintenance schedule, (4) development of an estimate of staffing requirements, and (5) development of a budget estimate for execution of the recommended PM program with breakout for costs, detailed annually for a period of 25 years. This study also identified, prioritized, and separately broke out new technologies and associated costs that would significantly improve the reliability of the existing CHPP.

15. SUBJECT TERMS

Ft.Wainwright, AK	central heating plants (CHP's)	maintenance
preventive maintenance	energy conservation	power plants

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